Site Specific Test Plan Rev. 1

Outrigger DJ Operating LLC
1200 17th Street, Suite 900
Denver, Colorado 80202

Makena Gas Plant
Weld County, Colorado

(1) Amine Reboiler (AIRS 004)
NOx & CO – Performance Test
(3) Waukesha L-7044GSI Engines (AIRS 007, 008 & 010)
NOx, CO, VOC & HCHO – Performance Test

Proposed Test Dates: June 12-14, 2019

AST Project No. 2019-0812D

Prepared By
Alliance Source Testing, LLC
5530 Marshall Street
Arvada, Colorado 80002

MAIN OFFICE
255 Grant Street SE
Suite 600
Decatur, AL 35601
(256) 351-0121

stacktest.com

REGIONAL OFFICES
Anchorage, AK
Baton Rouge, LA
Birmingham, AL
Cedar Rapids, IA
Decatur, AL
Denver, CO
Houston, TX
Lewisville, TX
Little Rock, AR
Philadelphia, PA
Pittsburgh, PA
Roanoke, VA
Salt Lake City, UT

Regulatory Information

Permit No.(s)	CDPHE Construction Permit No. 18WE0503, CDPHE General Permit GP02
Regulatory Citation(s)	40 CFR Part 60, Subpart DDDDD, 40 CFR Part 60, Subpart JJJJ

Source Information

Source Name	*Target Parameter(s)*
(1) Amine Reboiler (AIRS 004)	NOx, CO
(3) Waukesha L-7044GSI Engines (AIRS 007, 008, 010)	NOx, CO, VOC, HCHO

Contact Information

Test Location

Makena Gas Plant
NESE SEC 25 T8N R62W
Weld County, Colorado

Outrigger DJ Operating LLC
1200 17th Street, Suite 900
Denver, Colorado 80202

Area Operations Manager
Rich Goetz
307-680-8143
rgoetz@outriggerenergy.com

Project Air Quality Scientist
LT Environmental, Inc.
4600 W 60th Ave,
Arvada, Colorado 80003

Chris DiMarco
(303) 704-1066
cdimarco@ltenv.com

Test Company

Alliance Source Testing, LLC
5530 Marshall Street
Arvada, Colorado 80002

Project Manager
David Maiers
720-457-9515
david.maiers@stacktest.com

QA/QC Manager
Heather Morgan
256-260-3972
heather.morgan@stacktest.com

Test Plan/Report Coordinator
Marty Willinger
720-457-9521
martin.willinger@stacktest.com

Regulatory

USEPA Region 8
1595 Wynkoop Street
NC-8ENF-AT
Denver, Colorado 80202

Office of Enforcement, Compliance &
Environmental Justice
Alexis North,
303-312-7005
North.Alexis@epa.gov

CDPHE, APCD-SS-B1
4300 Cherry Creek Drive South
Denver, Colorado 80246
cdphe_apcd_compliancetesting@state.co.us

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICES

1. Introduction

Alliance Source Testing, LLC (AST) was retained by Outrigger DJ Operating LLC to conduct emission testing services at the Makena Gas Plant located in Weld County, Colorado. Testing will include determining the emission rates of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC) and formaldehyde (HCHO) from three (3) Waukesha L-7044GSI natural gas fired compressor engines (AIRS 007, 008 & 010) and NOx and CO from one (1) natural gas fired amine reboiler (AIRS 004).

The performance test on the three (3) Waukesha L-7044GSI engines (AIRS 007, 008 & 010) will be used to demonstrate initial compliance with 40 CFR Part 60, Subpart JJJJ and Colorado Department of Public Health and Environment (CDPHE) General Construction Permit No. GP02 and the performance test on the amine reboiler (AIRS 004) will be used to demonstrate compliance with CDPHE Air Quality Construction Permit 18WE0503, Issuance 1 and 40 CFR Part 60, Subpart DDDDD.

This site-specific test plan (SSTP) has been prepared to address the notification and testing requirements of the state permit and of 40 CFR Part 60, Subpart JJJJ.

2. Plant Description

The Makena Gas Plant (AIRS 123/9FC0) is a natural gas processing plant and is located in the northeast/southeast section 26, township 8 north, range 62 west of Weld County, Colorado.

One (1) Methyldiethanolamine (MDEA) natural gas sweetening unit for acid gas removal is in service at the plant. This amine unit is equipped with a natural gas/amine contactor, condenser, flash tank, still vent and natural gas fired amine regeneration reboiler (ARIS 004). Emissions from the flash tank are used as fuel for the amine reboiler or sent to the plant fuel system.

Three (3) Waukesha L7044GSI natural gas fired engines (AIRS 007, 008 & 010) are in service for the compression of natural gas. The engines are four stroke rich burn (4SRB), site rated at 1,680 brake horsepower (bhp), and equipped with non selective catalytic reduction (NSCR) system and air fuel ratio controller (AFRC) for emission controls.

3. Process Description

The amine reboiler (AIRS 004) performance test will consist of three (3), 60-minute test runs to determine the emission rates of NOx and CO during a high operating condition. Concurrent stack gas velocity, volumetric flow rate (VFR), oxygen (O_2), carbon dioxide (CO_2) and moisture (H_2O) measurements will be collected for the determination of NOx and CO emissions in units of pounds per hour (lb/hr), pounds per month (lb/mo) and tons per year (tpy). The performance testing will be conducted with the source operating at greater than 90% load or at the highest achievable load.

The performance test on the three (3) Waukesha L-7044GSI 4SRB Engines (AIRS 007, 008, 010) will consist of three (3), 60-minute test runs at a high operation load and three (3), 30-minute test runs at a low load operating condition. The high load condition will be with the engine operating at greater than 90% load or at the highest achievable load. Concurrent stack gas velocity, VFR, O_2, CO_2 and H_2O measurements will be collected for the

ED_004016P_00012008-00004

determination of NOx, CO, VOC and HCHO emissions in units of lb/hr, lb/mo, tpy and grams per break horsepower-hour (g/bhp-hr). VOC emissions reported will exclude the contribution of methane and ethane.

A complete 3 run high load performance test will be conducted on all three (3) engines. Since the three (3) Waukesha L-7044GSI 4SRB Engines (AIRS 007, 008, 010) in this test program are identical. It is proposed to use a 30-minute spot check test run during the low operating loads for the other two (2) engines, if the emissions measured during the spot checks are in compliance and not more than 10% (mass rate comparison), or 0.1 pounds per hour (lb/hr), whichever is greater, above the emissions measured during the complete performance test (high and low load testing), then the spot check is valid. Emissions for an engine with a valid spot check will be reported the same as the complete performance test engine's emissions for the low load operating condition. If the 10% or 0.1 lb/hr criteria are not met or the engine is out of compliance, a full set of three test runs will be completed at the low load for that engine.

Unit operating, and control equipment parameters will be recorded throughout the test program by Makena Gas Plant personnel for inclusion in the test report, including;
Engines -

- AFRC Set Point
- Catalyst Inlet Temperature
- Catalyst Pressure-Drop
- Engine Operating Load

Reboiler -

- Fuel Consumption
- Amine Recirculation Rate
- Amine Gas Throughput

Source identification and permitted emission limits are summarized in Table 1.

Table 1
Source Identification Summary

Source Identification	Emission Standards for Required Testing	
(1) Amine Reboiler (AIRS 004)	<u>CDPHE Permit 18WE0503</u> NOx: 795 lb/mo, 4.7 tpy CO: 680 lb/mo, 4.0 tpy	--
(3) Waukesha L-7044GSI 4SRB Engines (AIRS 007, 008, 010) SN: 5283705576, 5283705726, 5283704171 Capacity: 1,680 bhp	<u>CDPHE Permit GP02</u> NOx: 0.35 g/bhp-hr, 5.68 tpy CO: 0.5 g/bhp-hr, 8.11 tpy VOC: 0.7 g/bhp-hr, 11.36 tpy HCHO: 0.05 g/bhp-hr, 0.81 tpy T_{CAT}: 750-1,250°F	<u>40 CFR Part 60, Subpart JJJJ</u> NOx: 1.0 g/bhp-hr CO: 2.0 g/bhp-hr VOC: 0.7 g/bhp-hr

4. Permits and Regulations

The test program will determine the compliance status of the units with respect to the applicable emission limits provided in 40 CFR Part 60, Subpart JJJJ and CDPHE General Construction Permit No. GP02 for (3) Waukesha L-

7044GSI 4SRB Engines (AIRS 007, 008, 010) and the performance test on the amine reboiler (AIRS 004) will be used to demonstrate compliance with CDPHE Air Quality Construction Permit 18WE0503, Issuance 1 and 40 CFR Part 60, Subpart DDDDD. Permit 18WE0503 and the APEN for the engines are provided in Appendix B.

5. Stack Schematic

The stack diameter, upstream and downstream disturbance distances and nipple lengths will be measured on site with a verification measurement provided by the Field Team Leader. Table 2 provides source identification, stack dimensions and the number of gas velocity sampling points. RM 2 sampling points will be in accordance with RM 1. A stratification test will be conducted to determine RM 3A sampling points. RM 25A and 320 sampling will be conducted from a single point.

Table 2
Sample Location Summary

Source Identification	Diameter (inches)	Port Location to Nearest Disturbance	Traverse Points
(1) Amine Reboiler (AIRS 004)	24"	Upstream: >1/2D Downstream: >2D	16
(3) Waukesha L-7044GSI 4SRB Engines (AIRS 007, 008, 010)	24"	Upstream: >1/2D Downstream: >2D	16

6. Methods

Testing is proposed to be performed in accordance with specifications stipulated in U.S. Environmental Protection Agency (EPA) Reference Test Methods (RM) 1, 2, 3A, 25A and 320 referenced in 40 CFR Part 60, Appendix A and 40 CFR Part 63, Appendix A. The emissions testing program will provide all necessary equipment and labor for the determination of all emissions parameters detailed in Table 3. Gas analyzers will be housed in a mobile, analytical trailer to provide a temperature-controlled environment for stable, accurate analyzer response.

Table 3
Sampling and Analytical Methods

Parameter	EPA RM	Analytical Method
VFR	1, 2	Full Velocity Traverse
O_2, CO_2	3A	Paramagnetic and Non-Dispersive Infrared Analyzers
TVOC / NMOC	25A	Flame Ionization Analyzer
H_2O, NO, NO_2, NO_X, CO, HCHO, methane, ethane	320	Fourier Transform Infrared (FTIR) Spectrometer

6.1. U.S. EPA Reference Test Methods 1 and 2 - Stack Gas Velocity and Volumetric Flow Rate

Stack gas velocity and volumetric flow rate will be measured in accordance with EPA RM 1 and 2.

ED_004016P_00012008-00006

The sampling location and number of traverse points will be selected in accordance with EPA RM 1. To determine the minimum number of traverse points, the upstream and downstream distances will be equated into equivalent diameters and compared to Figure 1-2 in EPA RM 1.

Full velocity traverses will be conducted in accordance with EPA RM 2 to determine the stack gas velocity pressure, static pressure and temperature. The velocity and static pressure measurement system will consist of a pitot tube and inclined manometer. The stack gas temperature will be measured with a K-type thermocouple and pyrometer. The pitot assembly will be leak checked pre and post each sampling period.

The temperature and differential pressure traverse data will be combined with concurrently collected diluent data to calculate the stack gas velocity and volumetric flow rate in units of feet per second (ft/sec), actual cubic feet per minute (acfm), dry standard (1 atmosphere and 68°F) cubic feet per minute (dscfm), and pounds per hour (lb/hr).

6.2. U.S. EPA Reference Test Method 3A - Diluent (O_2 and CO_2)

O_2 and CO_2 emission concentrations will be measured in accordance with EPA RM 3A.

Each sampling period will consist of extracting a gas sample from the stack at a constant flow rate of approximately two liters per minute (lpm). The sample will pass through a refrigeration-type gas conditioner to remove moisture and into the sampling port of a Servomex Series 1400 paramagnetic O_2 / non-dispersive infrared CO_2 analyzer. The gas concentrations will be displayed on the analyzer front panels in units of percent, dry volume basis (%vd – O_2 and CO_2) and logged to a computerized data acquisition system (CDAS).

The initial three-point calibration test for each species will be conducted in direct calibration mode. Before and after each sampling period, the sample system will be challenged with calibration gases for a system bias check, and to quantify zero and span drift for the previous sampling period. The calibration gases will be prepared and certified in accordance with EPA Protocol 1.

The initial 3-point calibration error must be less than ±2% of the calibration span gas (CS). The sampling system bias recorded during the performance test must be less than ±5 percent of the CS. The zero and span calibration drift must not exceed ±3 percent of the CS over the period of each run. If the bias values exceed the specified limits, the run is void. If the drift values exceed the specified limits, the results will be reported using pre and post run calibration data. In both cases, another 3-point calibration and 2-point bias verification must be passed before the next run.

Prior to sampling, the stratification test procedures outlined in Section 8.1.2 of EPA RM 7E will be performed to determine the appropriate sampling points on stacks larger than 6 inches. The stratification test will be conducted using a single analyte of interest (O_2 or CO_2) along three (3) points (16.7%, 50.0%, and 83.3% of the stack diameter) passing through the centroidal area of the stack. If the stack gas is not stratified (concentrations are within +/- 5% or +/- 0.5 ppm of the mean concentration), a single measurement point will be selected.

Following sampling, the CDAS data will be averaged in one-minute increments, corrected for instrumental drift, and reported as average O_2 and CO_2 emission concentrations for each sampling period in units of %vd.

6.3. U.S. EPA Reference Test Method 25A - Volatile Organic Compounds

TVOC concentrations will be measured in accordance with EPA RM 25A using a hydrocarbon analyzer. If the hydrocarbon analyzer is equipped with a methane separator NMOC concentrations will be measured.

Each sampling period will consist of extracting a hot, wet gas sample from a single centrally located point in the stack at a constant flow rate of approximately two liters per minute using a heated Teflon line. The gas will be directed into a column of the Thermo Model 51i (TVOC) or 55C (NMOC) flame ionization analyzer. VOC concentrations will be displayed on the analyzer front panel in units of parts per million, wet volume basis (ppmvw – as propane) and logged to a CDAS.

Prior to sampling, the analyzer will be challenged with the zero and high-level EPA Protocol 1 calibration gases to linearize the instrument. Then the low and mid-level calibration gases will be introduced through the sampling system. The sampling system is acceptable, if the linear relationship between the zero and high-level calibration gases predict the low and mid-level calibration gas measurement system response within 5% of the respective calibration gas value. The time required for the analyzer reading to reach 95% of the high-level gas concentration will be recorded to determine the response time of the sampling system.

After each sampling period, the measurement system will be challenged with the zero and mid-level calibration gas. If the analyzer drift exceeds 3% of the analyzer span, then the system will be re-linearized with the zero and high-level calibration gases, and the measurement system verified with the low and mid-level calibration gases. If the drift limits are exceeded, the results will be reported using both sets of calibration data.

Following sampling, the CDAS data will be averaged in one-minute increments, corrected for instrumental drift, and reported as average emission concentrations for each sampling period. The concentration data will be combined with concurrently collected flow data to calculate VOC emissions as propane in units of lb/hr and g/bhp-hr.

6.3. U.S. EPA Reference Test Method 320 - Nitrogen Oxides, Carbon Monoxide, Formaldehyde and Moisture

NO_X, NO, NO_2, CO, HCHO, methane, ethane and H_2O emission concentrations will be measured in accordance with EPA RM 320 by extractive FTIR using an MKS 2030.

Each sampling period will consist of extracting a sample of gas at a constant flow rate from a single representative point of the exhaust stack. The sample will pass through a sample probe, through a heated Teflon sample line, through a heated head pump, through a heated Teflon jumper to the enclosed FTIR gas cell and then to the instrument detector. The FTIR gas cell will be maintained at 191°C. Sample measurements will be made approximately once every minute.

The FTIR will provide concentration values using MG 2000 software and R3 recipes. The gas concentrations will be reported in units of either parts per million, wet volume basis (ppmvw – NO_X, NO, NO_2, CO, HCHO, methane, and ethane), or percent, wet volume basis (%vw – H_2O) and logged to a computerized data acquisition system (CDAS). NOx, CO and HCHO emissions in units of lb/hr, lb/mo, tpy and g/bhp-hr.

Once per system set-up and prior to testing; (i) a screen shot of the peak analysis screen with laser frequency and FWHH values included, and (ii) a recovery check will be performed by spiking known concentrations of acetaldehyde (or other surrogate) with sulfur hexafluoride into the flue gas of the stacks via the calibration line of the heated sample line. The spiking levels and spike recoveries will demonstrate adequate system performance. For an additional daily quality check, the sample system will be challenged with NO and CO calibration gases for a system bias check. NO and CO concentrations will be approximately 100 ppm. All calibration gases will be prepared and certified in accordance with EPA Protocol 1. During one run the spectral residual and concentration validation check will be conducted for NO, NO_2, CO, H_2O, CO_2 and HCHO using the analysis validation utility (AVU) software from MKS.

A cylinder of nitrogen will be used for purging the instrument's optics. Nitrogen will be passed through the cell to obtain a back ground spectrum and at least eight blank spectra for error analysis and determining minimum detection limits in accordance with the ASTM D6348-03 pre-test MDC2 formula. A screen shot of the signal to noise ratio will be included in the report.

Before and after every run the path length of infrared light through the cell will be measured using a Calibration Transfer Standard (CTS) gas. The CTS gas will be approximately 100 ppm ethylene blended in nitrogen. The CTS pre and post run mean differences will meet the method's requirements (< 5% difference between CTS gas pre and post run measurements).

7. **Quality Control / Quality Assurance**

AST follows the procedures outlined in the Quality Assurance/Quality Control (QA/QC) Management Plan to ensure the continuous production of useful and valid data throughout the course of this test program. The QC checks and procedures described in this section represent an integral part of the overall sampling and analytical scheme. Adherence to prescribed procedures is quite often the most applicable QC check.

8. **Equations**

See Appendix C – Equations

9. **Data Sheets**

See Appendix D – Data Sheets

10. **Safety Requirements**

Testing personnel will undergo site-specific safety training for all applicable areas upon arrival at the site. AST personnel will have current OSHA or MSHA safety training and be equipped with hard hats, safety glasses with side shields, steel-toed safety shoes, hearing protection, fire resistant clothing, and fall protection (including shock-corded lanyards and full-body harnesses). AST personnel will comport themselves in a manner consistent with Client and AST's safety policies.

A Job Safety Analysis (JSA) will be completed daily by the AST Field Team Leader.

11. **Test Schedule**

The testing is scheduled for June 12-14, 2019. A two-person test team will be required for three (3), approximate 12-hour test days to complete the reference method testing. A schedule is proposed in Table 4. The actual test order of the engines will be determined by site personnel.

Table 4
Program Outline and Tentative Test Schedule

Date	EPA RM	Test Summary	
6/11	n/a	Mobilize to site, safety training, set-up test equipment	
6/12	1, 2, 3A, 320	Amine Reboiler (AIRS 004):	3, 60-minute test runs (high load)
	1, 2, 3A, 25A, 320	Waukesha L-7044GSI Engine (AIRS 007):	3, 60-minute test runs (high load) 3, 30-minute test runs (low load)
6/13	1, 2, 3A, 25A, 320	Waukesha L-7044GSI Engine (AIRS 008):	3, 60-minute test runs (high load) 3, 30-minute test runs (low load) *
6/14	1, 2, 3A, 25A, 320	Waukesha L-7044GSI Engine (AIRS 010):	3, 60-minute test runs (high load) 3, 30-minute test runs (low load) *
* Optional 30-mintue spot check run, if the emissions measured during the spot checks are in compliance and not more than 10%, or 0.1 lb/hr, whichever is greater, above the emissions measured during the complete performance test (high and low load testing),			

12. **Test Report**

The final test report must be submitted to CDPHE within 45-days of the completion of the testing and will include the following information.

- *Introduction* – Brief discussion of project scope of work and activities.
- *Results and Discussion* – A summary of test results and process/control system operational data with comparison to regulatory requirements or vendor guarantees along with a description of process conditions and/or testing deviations that may have affected the testing results.
- *Methodology* – A description of the sampling and analytical methodologies.
- *Sample Calculations* – Example calculations for each target parameter.
- *Field Data* – Copies of actual handwritten or electronic field data sheets.
- *Quality Control Data* – Copies of all instrument calibration data and/or calibration gas certificates.
- *Process Operating/Control System Data* – Process operating, control system data (as provided by Makena Gas Plant) to support the test results.

Appendix A

No Stack Schematics Provided

Appendix B

DRAFT

CONSTRUCTION PERMIT

Permit number: **18WE0503** Issuance: **1**

Date issued:

Issued to: **Outrigger DJ Operating LLC**

Facility Name:	Makena Gas Plant
Plant AIRS ID:	123/9FC0
Physical Location:	NESE SEC 25 T8N R62W
County:	Weld County
General Description:	Natural Gas Processing Plant

Equipment or activity subject to this permit:

Facility Equipment ID	AIRS Point	Equipment Description	Emissions Control Description
Amine Sweetening Unit	001	One (1) Methyldiethanolamine (MDEA) natural gas sweetening unit (Make: Dickson Process Systems, LLC, Model: TBD, SN: TBD) for acid gas removal with a design capacity of 60 MMscf per day. This emission unit is equipped with two (2) (Make: PumpWorks, Model: HP538-5500) electric driven amine recirculation pumps with a limited capacity of 146.1 gallons per minute of lean amine. Only one (1) amine recirculation pump will be operated at any given time. The second amine recirculation pump serves as a back-up only. This amine unit is equipped with a natural gas/amine contactor, condenser, flash tank, still vent and amine regeneration reboiler covered under point 123/9FC0/004.	Emissions from the flash tank are used as fuel for the amine reboiler or sent to the plant fuel system. The acid gas stream from the still vent is routed to a condenser and then to a thermal oxidizer.
Emergency Plant Flare (FS-1761)	002	One (1) open flare (Make: BCCK, Model: EEF-U-24) used to control residue gas during residue compressor downtime.	None
Amine Reboiler	004	One (1) (Make: TBD, Model: TBD, SN: TBD) natural gas fired amine regeneration heater	None

		with a design heat input rate of 10.9 MMBtu/hr.	
Fugitives	006	Fugitive emission component leaks from a natural gas processing plant.	None
Slop Tanks	009	Two (2) 400 barrel fixed roof storage vessels connected via liquid manifold. These vessels are used to store crude oil, water and slop oil from compressors.	Enclosed Combustion Device

This permit is granted subject to all rules and regulations of the Colorado Air Quality Control Commission and the Colorado Air Pollution Prevention and Control Act (C.R.S. 25-7-101 et seq), to the specific general terms and conditions included in this document and the following specific terms and conditions.

REQUIREMENTS TO SELF-CERTIFY FOR FINAL AUTHORIZATION

1. YOU MUST notify the Air Pollution Control Division (the Division) no later than fifteen days of the latter of commencement of operation or issuance of this permit, by submitting a Notice of Startup form to the Division for the equipment covered by this permit. The Notice of Startup form may be downloaded online at www.colorado.gov/pacific/cdphe/other-air-permitting-notices. Failure to notify the Division of startup of the permitted source is a violation of Air Quality Control Commission (AQCC) Regulation Number 3, Part B, Section III.G.1. and can result in the revocation of the permit.

2. Within one hundred and eighty days (180) of the latter of commencement of operation or issuance of this permit, compliance with the conditions contained in this permit shall be demonstrated to the Division. It is the owner or operator's responsibility to self-certify compliance with the conditions. Failure to demonstrate compliance within 180 days may result in revocation of the permit. A self certification form and guidance on how to self-certify compliance as required by this permit may be obtained online at www.colorado.gov/pacific/cdphe/air-permit-self-certification. (Regulation Number 3, Part B, Section III.G.2.)

3. This permit shall expire if the owner or operator of the source for which this permit was issued: (i) does not commence construction/modification or operation of this source within 18 months after either, the date of issuance of this construction permit or the date on which such construction or activity was scheduled to commence as set forth in the permit application associated with this permit; (ii) discontinues construction for a period of eighteen months or more; (iii) does not complete construction within a reasonable time of the estimated completion date. The Division may grant extensions of the deadline. (Regulation Number 3, Part B, Section III.F.4.)

4. The operator shall complete all initial compliance testing and sampling as required in this permit and submit the results to the Division as part of the self-certification process. (Regulation Number 3, Part B, Section III.E.)

5. **Point 001 & 004:** The following information shall be provided to the Division within fifteen (15) days of the latter of commencement of operation or issuance of this permit.

    - Manufacturer
    - Model Number
    - Serial Number

    This information shall be included with the Notice of Startup submitted for the equipment. (Regulation Number 3, Part B, III.E.)

6. The operator shall retain the permit final authorization letter issued by the Division, after completion of self-certification, with the most current construction permit. This construction permit alone does not provide final authority for the operation of this source.

EMISSION LIMITATIONS AND RECORDS

7. Emissions of air pollutants shall not exceed the following limitations. (Regulation Number 3, Part B, Section II.A.4.)

Monthly Limits:

Facility Equipment ID	AIRS Point	Process	Pounds per Month							Emission Type
			$PM_{2.5}$	PM_{10}	SO_x	H_2S	NO_x	VOC	CO	
Amine Sweetening Unit	001	01	---	---	714	34	51	476	51	Point
		02	---	---	17	---	510	136	425	
Emergency Plant Flare (FS-1761)	002	01	---	---	---	---	986	280	4,434	Point
Amine Reboiler	004	01	---	---	---	---	795	---	680	Point
Fugitives	006	01	---	---	---	---	---	3,992	---	Fugitive
Slop Tanks	009	02	---	---	---	---	---	306	---	Point

Note:

1. Monthly limits are based on a 31-day month.
2. Process 01 and 02 for the amine unit covered under point 001 are as follow:
   a. Process 01: Still vent waste gas routed to the thermal oxidizer.
   b. Process 02: Combustion of assist gas and pilot fuel by the thermal oxidizer.

The owner or operator shall calculate monthly emissions based on the calendar month.

Facility-wide emissions of each individual hazardous air pollutant shall not exceed 1,359 pounds per month.

Facility-wide emissions of total hazardous air pollutants shall not exceed 3,398 pounds per month.

The facility-wide emissions limitation for hazardous air pollutants shall apply to all permitted emission units at this facility.

Annual Limits:

Facility Equipment ID	AIRS Point	Process	Tons per Year							Emission Type
			$PM_{2.5}$	PM_{10}	SO_x	H_2S	NO_x	VOC	CO	
Amine Sweetening Unit	001	01	---	---	4.2	0.2	0.3	2.8	0.3	Point
		02	---	---	0.1	---	3.0	0.8	2.5	
Emergency Plant Flare (FS-1761)	002	01	---	---	---	---	5.8	1.7	26.1	Point
Amine Reboiler	004	01	---	---	---	---	4.7	---	4.0	Point

Fugitives	**006**	**01**	---	---	---	---	---	**23.5**	---	**Fugitive**
Slop Tanks	**009**	**01**	---	---	---	---	---	**1.8**	---	**Point**

Note:

1. See "Notes to Permit Holder" for information on emission factors and methods used to calculate limits.
2. Process 01 and 02 for the amine unit covered under point 001 are as follow:
   a. Process 01: Still vent waste gas routed to the thermal oxidizer.
   b. Process 02: Combustion of assist gas and pilot fuel by the thermal oxidizer.

Facility-wide emissions of each individual hazardous air pollutant shall not exceed 8.0 tons per year.

Facility-wide emissions of total hazardous air pollutants shall not exceed 20.0 tons per year.

The facility-wide emissions limitation for hazardous air pollutants shall apply to all permitted emission units at this facility.

During the first twelve (12) months of operation, compliance with both the monthly and annual emission limitations is required. After the first twelve (12) months of operation, compliance with only the annual limitation is required.

Compliance with the annual limits, for criteria and hazardous air pollutants, shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate actual emissions each month and keep a compliance record on site or at a local field office with site responsibility for Division review.

8. **Point 001:** Compliance with the emission limits in this permit shall be determined by using the monthly measured still vent waste gas sample composition and monthly measured waste gas flow volumes. The owner or operator shall calculate uncontrolled VOC, HAP, and H2S emissions on a monthly basis using the most recent measured waste gas sample composition and monthly measured waste gas flow volume. A control efficiency of 95%, based on operating the control device in accordance with the O&M Plan, shall be applied to the uncontrolled VOC, HAP and H2S emissions.

9. **Point 001:** 100% of emissions that result from the flash tank associated with the amine unit shall be recycled and used as fuel for the amine reboiler (AIRS Point 123/9CF0/004) or sent to the plant fuel system.

10. **Point 006:** The owner or operator shall calculate actual emissions from this emissions point based on representative component counts for the facility with the most recent inlet gas analysis, as required in the Compliance Testing and Sampling section of this permit. The owner or operator shall maintain records of the results of component counts and sampling events used to calculate actual emissions and the dates that these counts and events were completed. These records shall be provided to the Division upon request.

11. The owner or operator shall operate and maintain the emission points in the table below with the emissions control equipment as listed in order to reduce emissions to less than or equal to the limits established in this permit. (Regulation Number 3, Part B, Section III.E.)

Facility Equipment ID	AIRS Point	Control Device	Pollutants Controlled
Amine Sweetening Unit	001	Still Vent: Thermal Oxidizer (TO)	VOC & HAP

Slop Tanks	009	Enclosed Combustion Device	VOC & HAP

PROCESS LIMITATIONS AND RECORDS

12. This source shall be limited to the following maximum processing rates as listed below. Monthly records of the actual processing rates shall be maintained by the owner or operator and made available to the Division for inspection upon request. (Regulation Number 3, Part B, Section II.A.4.)

Process Limits

Facility Equipment ID	AIRS Point	Process	Process Parameter	Annual Limit	Monthly Limit (31 days)
Amine Sweetening Unit	001	---	Natural Gas Throughput	21,900 MMSCF	1,860 MMSCF
		01	Still vent waste gas routed to the thermal oxidizer	498.4 MMSCF	42.32 MMSCF
		02	Combustion of assist gas and pilot gas by the thermal oxidizer	55.63 MMSCF	4.72 MMSCF
Emergency Plant Flare (FS-1761)	002	01	Combustion of residue gas during residue compression downtime, purge gas and pilot fuel	154.5 MMSCF	13.12 MMSCF
Amine Reboiler	004	01	Consumption of natural gas as a fuel	87.8 MMSCF	7.46 MMSCF
Slop Tanks	009	01	Crude Oil Throughput	23,480 barrels	1,994 barrels

The owner or operator shall monitor monthly process rates based on the calendar month.

During the first twelve (12) months of operation, compliance with both the monthly and annual throughput limitations is required. After the first twelve (12) months of operation, compliance with only the annual limitation is required.

Compliance with the annual throughput limits shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve-month total is calculated based on the previous twelve months' data. The permit holder shall calculate throughput each month and keep a compliance record on site or at a local field office with site responsibility, for Division review.

13. **Point 001:** The owner or operator shall continuously monitor and record the following amine unit emission streams using continuous operational flow meters:

    - Total amine unit still vent waste gas volume routed to the thermal oxidizer,
    - Total assist gas volume routed to the thermal oxidizer.

    The owner or operator shall use monthly throughput records to demonstrate compliance with the process limits contained in the permit and to calculate emissions as described in this permit.

14. **Point 001:** The owner or operator shall continuously monitor and record the volumetric flow rate of natural gas processed by the amine unit contactor using an operational continuous flow meter at the inlet to the amine contactor. The owner or operator shall use monthly throughput records to demonstrate compliance with the process limits contained in this permit and to calculate emissions as described in this permit.

15. **Point 001**: This unit shall be limited to the maximum lean amine recirculation pump rate of 146.1 gallons per minute. The lean amine recirculation rate shall be recorded weekly in a log maintained on site and made available to the Division for inspection upon request. (Regulation Number 3, Part B, Section II.A.4)

16. **Point 002:** The owner or operator shall continuously monitor and record the following emission streams associated with the open flare using continuous operational flow meters at the inlet to the open flare:

    - Total residue gas volume routed to the open flare,
    - Total purge gas volume routed to the open flare.

    The owner or operator shall use monthly throughput records to demonstrate compliance with the process limits contained in the permit and to calculate emissions as described in this permit.

17. **Point 004:** The owner or operator shall continuously monitor and record the volumetric flow rate of natural gas combusted as fuel by the amine regeneration heater using an operational continuous flow meter at the inlet to the amine regeneration heater. The owner or operator shall use monthly throughput records to demonstrate compliance with the process limits contained in this permit and to calculate emissions as described in this permit.

<u>STATE AND FEDERAL REGULATORY REQUIREMENTS</u>

18. The permit number and ten digit AIRS ID number assigned by the Division (e.g. 123/4567/001) shall be marked on the subject equipment for ease of identification. (Regulation Number 3, Part B, Section III.E.) (State only enforceable)

19. This source is subject to the odor requirements of Regulation Number 2. (State only enforceable)

20. **Points 001, 004, 006 & 009:** This source is located in an ozone non-attainment or attainment-maintenance area and subject to the Reasonably Available Control Technology (RACT) requirements of Regulation Number 3, Part B, Section III.D.2.B. The following requirements were determined to be RACT for this source:

Facility Equipment ID	AIRS Point	RACT	Pollutants
Amine Sweetening Unit	**001**	**Flash Tank:** Recycled and used as amine reboiler fuel or in the plant fuel system.	VOC
		Still Vent: Thermal Oxidizer	
Amine Reboiler	**004**	Natural gas as fuel and good combustion practices	VOC, NOx
Fugitives	**006**	LDAR as provided at 40 CFR Part 60 Subpart OOOOa	VOC
Slop Tanks	**009**	Enclosed Combustion Device	VOC

21. **Point 001, 004 & 006:** Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes. (Regulation Number 1, Section II.A.1. & 4.)

22. **Point 002:** No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes. (Regulation Number 1, Section II.A.5.)

DRAFT

23. **Point 004:** This source is subject to the Particulate Matter and Sulfur Dioxide Emission Regulations of Regulation Number 1 including, but not limited to, the following (Regulation Number 1, Section III.A.1):

a. No owner or operator shall cause or permit to be emitted into the atmosphere from any fuel-burning equipment, particulate matter in the flue gases which exceeds the following (Regulation Number 1, Section III.A.1.):

(i) For fuel burning equipment with designed heat inputs greater than $1x10^6$ BTU per hour, but less than or equal to $500x10^6$ BTU per hour, the following equation will be used to determine the allowable particulate emission limitation.

$PE=0.5(FI)^{-0.26}$
Where:
PE = Particulate Emission in Pounds per million BTU heat input.
FI = Fuel Input in Million BTU per hour.

b. Emissions of sulfur dioxide shall not emit sulfur dioxide in excess of the following limitations. (Heat input rates shall be the manufacturer's guaranteed maximum heat input rates).

(i) Limit emissions to not more than two (2) tons per day of sulfur dioxide (Regulation Number 1, Section VI.B.5.a.)

24. **Point 004:** This source is subject to the New Source Performance Standards requirements of Regulation Number 6, Part B including, but not limited to, the following (Regulation Number 6, Part B, Section II.C.):

a. Standard for Particulate Matter - On and after the date on which the required performance test is completed, no owner or operator subject to the provisions of this regulation may discharge, or cause the discharge into the atmosphere of any particulate matter which is:

(i) For fuel burning equipment generating greater than one million but less than 250 million Btu per hour heat input, the following equation will be used to determine the allowable particulate emission limitation:

$PE=0.5(FI)^{-0.26}$
Where:
PE is the allowable particulate emission in pounds per million Btu heat input.
FI is the fuel input in million Btu per hour.
If two or more units connect to any opening, the maximum allowable emission rate shall be the sum of the individual emission rates.

(ii) Greater than 20 percent opacity.

25. **Point 004:** This source is subject to the New Source Performance Standards requirements of Regulation Number 6, Part A, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units including, but not limited to the following:

- §60.48c Reporting and recordkeeping requirements:
  - §60.48c(a) - The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:
    - §60.48c(a)(1) - The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
  - §60.48c(g)(1) - Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

- §60.48c(g)(2) - As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
- §60.48c(i) - All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

26. **Point 006:** This source is subject to Regulation Number 7, Section XII.G.1. (State only enforceable). For fugitive volatile organic compound emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOO (July 1, 2017) applies, regardless of the date of construction of the affected facility, unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOOa (July 1, 2017).

27. **Point 009:** The combustion device covered by this permit is subject to Regulation Number 7, Section XVII.B.2. General Provisions (State only enforceable). If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Section XVII, it shall be enclosed; have no visible emissions during normal operations, as defined under Regulation Number 7, XVII.A.17; and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means approved by the Division, determine whether it is operating properly. This flare must be equipped with an operational auto-igniter according to the following schedule:

    - All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device;
    - All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

28. **Point 009:** The storage tank covered by this permit is subject to the emission control requirements in Regulation Number 7, Section XVII.C.1. The owner or operator shall install and operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons except where the combustion device has been authorized by permit prior to May 1, 2014. The source shall follow the inspection requirements of Regulation Number 7, Section XVII.C.1.d. and maintain records of the inspections for a period of two years, made available to the Division upon request. This control requirement must be met within 90 days of the date that the storage tank commences operation.

29. **Point 009:** The storage tanks covered by this permit are subject to the venting and Storage Tank Emission Management System ("STEM") requirements of Regulation Number 7, Section XVII.C.2.

OPERATING & MAINTENANCE REQUIREMENTS

30. **Points 001-002 & 009:** Upon startup of these points, the owner or operator shall follow the most recent operating and maintenance (O&M) plan and record keeping format approved by the Division, in order to demonstrate compliance on an ongoing basis with the requirements of this permit. Revisions to the O&M plan are subject to Division approval prior to implementation. (Regulation Number 3, Part B, Section III.G.7.)

COMPLIANCE TESTING AND SAMPLING

Initial Testing Requirements

31. **Point 001:** The owner or operator shall complete an initial site specific extended gas analysis of the amine unit still vent waste gas stream within one hundred and eighty days (180) after commencement of operation or issuance of this permit, whichever comes later. The sample shall be analyzed for total VOC, Benzene, Toluene, Ethylbenzene, Xylene, n-Hexane, 2,2,4-Trimethylpentane and H_2S content. The sample shall be collected prior to the inlet of the thermal

oxidizer and prior to being combined with any other stream. Results of the sampled data will be used to calculate VOC, HAP and H_2S emissions as specified in this permit. Results of the sampled data shall be submitted to the Division as part of the self-certification process to demonstrate compliance with emission limits.

32. **Point 001:** The owner/operator shall complete an initial site specific extended gas analysis ("Analysis") within one hundred and eighty days (180) after commencement of operation or issuance of this permit, whichever comes later, of the residue gas combusted as assist gas and pilot fuel by the thermal oxidizer in order to verify the VOC, benzene, toluene, ethylbenzene, xylenes, n-hexane, 2,2,4-trimethylpentane, methanol and hydrogen sulfide content (weight fraction) of this emission stream. Results of the Analysis shall be used to calculate site-specific emission factors for the pollutants referenced in this permit (in units of lb/MMSCF gas vented) using Division approved methods. Results of the Analysis shall be submitted to the Division as part of the self-certification and must demonstrate the emissions factors established through the Analysis are less than or equal to, the emissions factors submitted with the permit application and established herein in the "Notes to Permit Holder" for this emissions point. If any site specific emissions factor developed through this Analysis is greater than the emissions factors submitted with the permit application and established in the "Notes to Permit Holder" the operator shall submit to the Division within 60 days, or in a timeframe as agreed to by the Division, a request for permit modification to address this/these inaccuracy(ies).

33. **Point 002:** The owner/operator shall complete an initial site specific extended gas analysis ("Analysis") within one hundred and eighty days (180) after commencement of operation or issuance of this permit, whichever comes later, of the residue gas routed to and controlled by the open flare in order to verify the VOC, benzene, toluene, ethylbenzene, xylenes, n-hexane, 2,2,4-trimethylpentane, methanol and hydrogen sulfide content (weight fraction) of this emission stream. Results of the Analysis shall be used to calculate site-specific emission factors for the pollutants referenced in this permit (in units of lb/MMSCF gas vented) using Division approved methods. Results of the Analysis shall be submitted to the Division as part of the self-certification and must demonstrate the emissions factors established through the Analysis are less than or equal to, the emissions factors submitted with the permit application and established herein in the "Notes to Permit Holder" for this emissions point. If any site specific emissions factor developed through this Analysis is greater than the emissions factors submitted with the permit application and established in the "Notes to Permit Holder" the operator shall submit to the Division within 60 days, or in a timeframe as agreed to by the Division, a request for permit modification to address this/these inaccuracy(ies).

34. **Point 004:** A source initial compliance test shall be conducted on this heater to measure the emission rate(s) for the pollutants listed below in order to demonstrate compliance with the emissions limits contained in this permit. The test protocol must be in accordance with the requirements of the Air Pollution Control Division Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No compliance test shall be conducted without prior approval from the Division. Any compliance test conducted to show compliance with a monthly or annual emission limitation shall have the results projected up to the monthly or annual averaging time by multiplying the test results by the allowable number of operating hours for that averaging time (Regulation Number 3, Part B., Section III.G.3)

    Oxides of Nitrogen using EPA approved methods.
    Carbon Monoxide using EPA approved methods.

35. **Point 006:** Within one hundred and eighty days (180) of the latter of commencement of operation or issuance of this permit, the owner or operator shall complete the initial extended gas analysis of gas samples that are representative of volatile organic compound (VOC) and hazardous air pollutants (HAP) that may be released as fugitive emissions. This extended gas analysis shall be used in the compliance demonstration as required in the Emission Limits and Records section of this permit. The operator shall submit the results of the gas analysis and emission calculations to the Division as part of the self-certification process to ensure compliance with emissions limits.

36. **Point 006:** Within one hundred and eighty days (180) of the latter of commencement of operation or issuance of this permit, the operator shall complete a hard count of components at the source and establish the number of components that are operated in "heavy liquid service", "light liquid service", "water/oil service" and "gas service". The operator shall submit the results to the Division as part of the self-certification process to ensure compliance with emissions limits.

37. **Point 009:** The owner or operator shall complete site specific sampling including a compositional analysis of the pre-flash pressurized crude oil routed to these storage tanks and for emission factor development, a sales oil analysis to determine RVP and API gravity. Testing shall be in accordance with the guidance contained in PS Memo 05-01. Results of testing shall be used to determine site-specific emissions factors for VOC and Hazardous Air Pollutants using Division approved methods. Results of site-specific sampling and analysis shall be submitted to the Division as part of the self-certification and used to demonstrate compliance with the emissions factors chosen for this emissions point.

<u>Periodic Testing Requirements</u>

38. **Point 001:** At a minimum frequency of once per calendar month, the owner or operator shall sample and complete an extended gas analysis of amine unit still vent waste gas. This sample shall be analyzed for total VOC, Benzene, Toluene, Ethylbenzene, Xylene, n-Hexane, 2,2,4-trimethylpentane and H2S content. The sample shall be collected prior to the inlet of the thermal oxidizer and prior to being combined with any other stream. The sampled data will be used to calculate VOC and H2S emissions specified in this permit. If an amine unit is not operated during a calendar month, monthly sampling is not required.

39. **Point 006:** On an annual basis, the owner or operator shall complete an extended gas analysis of gas samples that are representative of volatile organic compounds (VOC) and hazardous air pollutants (HAP) that may be released as fugitive emissions. This extended gas analysis shall be used in the compliance demonstration as required in the Emission Limits and Records section of this permit.

<u>ADDITIONAL REQUIREMENTS</u>

40. A revised Air Pollutant Emission Notice (APEN) shall be filed: (Regulation Number 3, Part A, Section II.C.)

- Annually by April 30th whenever a significant increase in emissions occurs as follows:

  For any criteria pollutant:

  For sources emitting **less than 100 tons per year**, a change in actual emissions of five (5) tons per year or more, above the level reported on the last APEN; or

  For volatile organic compounds (VOC) and nitrogen oxides sources (NO_x) in ozone nonattainment areas emitting **less than 100 tons of VOC or NO_x per year**, a change in annual actual emissions of one (1) ton per year or more or five percent, whichever is greater, above the level reported on the last APEN; or

  For sources emitting **100 tons per year or more**, a change in actual emissions of five percent or 50 tons per year or more, whichever is less, above the level reported on the last APEN submitted; or

  For any non-criteria reportable pollutant:

  If the emissions increase by 50% or five (5) tons per year, whichever is less, above the level reported on the last APEN submitted to the Division.

- Whenever there is a change in the owner or operator of any facility, process, or activity; or

- Whenever new control equipment is installed, or whenever a different type of control equipment replaces an existing type of control equipment; or
- Whenever a permit limitation must be modified; or
- No later than 30 days before the existing APEN expires.

41. The requirements of Colorado Regulation Number 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Regulation Number 3, Part D, Section V.A.7.B).

42. **Point 006:** MACT Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities major stationary source requirements shall apply to this stationary source at any such time that this stationary source becomes major solely by virtue of a relaxation in any permit limitation and shall be subject to all appropriate applicable requirements of Subpart HH. (Reference: Regulation Number 8, Part E)

43. **Point 004:** MACT Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters requirements shall apply to this source at any such time that this source becomes a major source of hazardous air pollutants (HAP) solely by virtue of a relaxation in any permit limitation and shall be subject to all appropriate applicable requirements of that Subpart on the date as stated in the rule as published in the Federal Register. (Reference: Regulation Number 8, Part E)

GENERAL TERMS AND CONDITIONS

44. This permit and any attachments must be retained and made available for inspection upon request. The permit may be reissued to a new owner by the APCD as provided in AQCC Regulation Number 3, Part B, Section II.B. upon a request for transfer of ownership and the submittal of a revised APEN and the required fee.

45. If this permit specifically states that final authorization has been granted, then the remainder of this condition is not applicable. Otherwise, the issuance of this construction permit does not provide "final" authority for this activity or operation of this source. Final authorization of the permit must be secured from the APCD in writing in accordance with the provisions of 25-7-114.5(12)(a) C.R.S. and AQCC Regulation Number 3, Part B, Section III.G. Final authorization cannot be granted until the operation or activity commences and has been verified by the APCD as conforming in all respects with the conditions of the permit. Once self-certification of all points has been reviewed and approved by the Division, it will provide written documentation of such final authorization. **Details for obtaining final authorization to operate are located in the Requirements to Self-Certify for Final Authorization section of this permit.**

46. This permit is issued in reliance upon the accuracy and completeness of information supplied by the owner or operator and is conditioned upon conduct of the activity, or construction, installation and operation of the source, in accordance with this information and with representations made by the owner or operator or owner or operator's agents. It is valid only for the equipment and operations or activity specifically identified on the permit.

47. Unless specifically stated otherwise, the general and specific conditions contained in this permit have been determined by the APCD to be necessary to assure compliance with the provisions of Section 25-7-114.5(7)(a), C.R.S.

48. Each and every condition of this permit is a material part hereof and is not severable. Any challenge to or appeal of a condition hereof shall constitute a rejection of the entire permit and upon such occurrence, this permit shall be deemed denied *ab initio*. This permit may be revoked at any time prior to self-certification and final authorization by the Air Pollution Control Division (APCD) on grounds set forth in the Colorado Air Quality Control Act and regulations of the Air

Quality Control Commission (AQCC), including failure to meet any express term or condition of the permit. If the Division denies a permit, conditions imposed upon a permit are contested by the owner or operator, or the Division revokes a permit, the owner or operator of a source may request a hearing before the AQCC for review of the Division's action.

49. Section 25-7-114.7(2)(a), C.R.S. requires that all sources required to file an Air Pollution Emission Notice (APEN) must **pay an annual fee** to cover the costs of inspections and administration. If a source or activity is to be discontinued, the owner must notify the Division in writing requesting a cancellation of the permit. Upon notification, annual fee billing will terminate.

50. Violation of the terms of a permit or of the provisions of the Colorado Air Pollution Prevention and Control Act or the regulations of the AQCC may result in administrative, civil or criminal enforcement actions under Sections 25-7-115 (enforcement), -121 (injunctions), -122 (civil penalties), -122.1 (criminal penalties), C.R.S.

By:

Harrison Slaughter
Permit Engineer

Permit History

Issuance	Date	Description
Issuance 1	This Issuance	Issued to Outrigger DJ Operating LLC Permit for one (1) 60 MMscf/day MDEA natural gas sweetening unit, one (1) plant flare, one (1) 10.9 MMBtu/hr amine regeneration heater, fugitives, and two (2) 400 barrel fixed roof storage vessels at a new natural gas processing facility located in the ozone non-attainment area.

Notes to Permit Holder at the time of this permit issuance:

1) The permit holder is required to pay fees for the processing time for this permit. An invoice for these fees will be issued after the permit is issued. The permit holder shall pay the invoice within 30 days of receipt of the invoice. Failure to pay the invoice will result in revocation of this permit. (Regulation Number 3, Part A, Section VI.B.)

2) The production or raw material processing limits and emission limits contained in this permit are based on the consumption rates requested in the permit application. These limits may be revised upon request of the owner or operator providing there is no exceedance of any specific emission control regulation or any ambient air quality standard. A revised air pollution emission notice (APEN) and complete application form must be submitted with a request for a permit revision.

3) This source is subject to the Common Provisions Regulation Part II, Subpart E, Affirmative Defense Provision for Excess Emissions During Malfunctions. The owner or operator shall notify the Division of any malfunction condition which causes a violation of any emission limit or limits stated in this permit as soon as possible, but no later than noon of the next working day, followed by written notice to the Division addressing all of the criteria set forth in Part II.E.1 of the Common Provisions Regulation. See: https://www.colorado.gov/pacific/cdphe/aqcc-regs

4) The following emissions of non-criteria reportable air pollutants are estimated based upon the process limits as indicated in this permit. This information is listed to inform the operator of the Division's analysis of the specific compounds emitted if the source(s) operate at the permitted limitations.

Facility Equipment ID	AIRS Point	Pollutant	CAS #	Uncontrolled Emissions (lb/yr)	Controlled Emissions (lb/yr)
Amine Sweetening Unit	001	Benzene	71432	27,814	1,347
		Toluene	108883	12,313	599
		Ethylbenzene	100414	704	35
		Xylenes	1330207	2,490	123
		n-Hexane	110543	789	7
		2,2,4-Trimethylpentane	540841	0.1	4.0×10^{-4}
		Hydrogen Sulfide	7783064	4,400	220
Emergency Plant Flare (FS-1761)	002	Hydrogen Sulfide	7783064	3	1
Amine Reboiler	004	Formaldehyde	50000	7	7
		Benzene	71432	0.2	0.2
		Toluene	108883	0.3	0.3
		n-Hexane	110543	169	169
Fugitives	006	Benzene	71432	408	408
		Toluene	108883	826	826
		Ethylbenzene	100414	251	251
		Xylenes	1330207	674	674
		n-Hexane	110543	2,158	2,158

		2,2,4-Trimethylpentane	540841	4	4
		Methanol	67561	18	18
Slop Tanks	009	Benzene	71432	371	19
		Toluene	108883	252	13
		Ethylbenzene	100414	25	2
		Xylenes	1330207	60	3
		n-Hexane	110543	2,118	106
		2,2,4-Trimethylpentane	540841	2	0.1
		Hydrogen Sulfide	7783064	1	0.1
		Methanol	67561	9	1

Note: All non-criteria reportable pollutants in the table above with uncontrolled emission rates above 250 pounds per year (lb/yr) are reportable and may result in annual emission fees based on the most recent Air Pollution Emission Notice.

5) The emission levels contained in this permit are based on the following emission factors:

Point 001:

Process 01:

Emissions from the amine unit result from venting of acid gas (still vent overhead). Additionally, emissions result from the combustion of thermal oxidizer (TO) assist gas and pilot fuel. Actual VOC, HAP and H_2S emissions from the venting of still vent acid gas shall be calculated based on the most recent monthly still vent waste gas sampling and the most recent monthly measured still vent waste gas flow volume. The following equation shall be used to in conjunction with the sample and flow volume data to calculate actual emissions:

$$Emission\ Rate_X = \frac{Weight\ \%_X}{100} x \frac{Sample\ MW, lb}{lb-mole} x \frac{lb-mole}{379\ scf} x \frac{1.0x10^6\ scf}{1\ MMscf} x \frac{Metered\ Still\ Vent\ Volume, MMscf}{Month}$$

Controlled emissions are as follows:

Point Source	Control Efficiency
Still vent controlled by thermal oxidizer	95%
Flash tank recycled and used as fuel for amine unit reboiler or in plant fuel system	100%

SO_2 emissions resulting from the combustion of H_2S emissions in the still vent waste gas stream are based on a mass balance. The mass balance utilizes molecular weights of 64.066 lb SO_2/lb-mol and 34.08088 lb H_2S/lb-mol. The calculation assumes 100% of H_2S in the still vent waste gas stream is converted to SO_2 when combusted by the thermal oxidizer. The following equation shall be used to calculate actual SO_2 emissions:

$$SO_2\ Emission\ Rate\left(\frac{lb}{month}\right) = \frac{H_2S\ Still\ Vent\ Emission\ Rate, lb}{month} x \frac{64.066\ lb\ SO_2}{lb-mol} x \frac{lb-mol}{34.08088\ lb\ H_2S}$$

Emissions associated with the combustion of still vent waste gas by the thermal oxidizer are calculated using the following emission factors:

CAS #	Pollutant	Uncontrolled Emission Factors (lb/MMSCF)	Controlled Emission Factors (lb/MMSCF)	Source
	NOx	1.032	1.032	AP-42 Chapter 1.4 Table 1.4-1
	CO	$8.67x10^{-1}$	$8.67x10^{-1}$	AP-42 Chapter 1.4 Table 1.4-1

Note: Emission factors in the table above are based on a still vent waste gas heat content of 10.522 Btu/scf. Actual emissions are calculated by multiplying the emission factors in the table above by the total metered amine unit still vent waste gas routed to the thermal oxidizer.

Process 02:

Combustion of assist gas and pilot fuel:

CAS #	Pollutant	Uncontrolled Emission Factors (lb/MMSCF)	Controlled Emission Factors (lb/MMSCF)	Source
	NOx	106.61	106.61	AP-42 Chapter 1.4 Table 1.4-1
	CO	89.56	89.56	AP-42 Chapter 1.4 Table 1.4-1
	SOx	$6.4x10^{-1}$	$6.4x10^{-1}$	AP-42 Chapter 1.4 Table 1.4-2
	VOC	511.36	25.57	Mass Balance
7783064	Hydrogen Sulfide	$2.17x10^{-2}$	$1.09x10^{-3}$	Mass Balance

Note: NOx and CO emission factors in the table above are based on a residue gas heat content of 1087.47 Btu/scf. Actual emissions are calculated by multiplying the emission factors in the table above by the supplemental fuel volume for the thermal oxidizer (as measured by flow meter) plus the fuel volume to the thermal oxidizer pilot (constant at 50 scf/hr). The VOC and HAP emission factors in the table above were calculated based on the residue gas composition in the ProMax simulation in conjunction with the EPA Emission Inventory Improvement Program Publication: Volume II, Chapter 10 - Displacement Equation (10.4-3). The ProMax simulation is based on a representative gas analysis obtained from an upstream facility on 09/13/2012. The controlled VOC and HAP emission factors are based on the thermal oxidizer control efficiency of 95%.

Point 002:

Emissions associated with the open flare result from the combustion of residue gas during residue compressor downtime, purge gas and pilot light gas. Total actual emissions are based on the sum of emissions calculated for the combustion of residue gas, purge gas and pilot light gas (150 scf/hr).

CAS #	Pollutant	Uncontrolled Emission Factors (lb/MMSCF)	Controlled Emission Factors (lb/MMSCF)	Source
	NOx	73.95	73.95	AP-42 Chapter 13.5
	CO	337.13	337.13	AP-42 Chapter 13.5
	VOC	426.13	21.31	Mass Balance

Note: The uncontrolled VOC emission factor was calculated based on the residue gas composition in the ProMax simulation provided with the application. The ProMax simulation is based on a representative sales gas analyses obtained from an upstream facility (Hemberger 3-26-34-8-60) on 09/13/2012. The controlled VOC emission factor is based on the open flare control efficiency of 95%. The NOx and CO emission factors from AP-42 Chapter

13.5 (0.068 lb/MMBtu and 0.31 lb/MMBtu respectively) were converted to units of lb/MMscf using a heat content of 1,087.47 Btu/scf. Actual emissions are calculated by multiplying the emission factors in the table above by the total gas volume routed to the flare as measured by flow meter (residue and purge gas) plus the pilot gas fuel use. The pilot gas fuel use is calculated using a constant rate of 150 scf/hr.

Point 004:

CAS #	Pollutant	Uncontrolled Emission Factors lb/MMscf	Source
	NOx	106.61	AP-42 Chapter 1.4 Table 1.4-1
	CO	89.56	

Note: The emissions factors for this point are based on a rated heat input of 10.9 MMBtu/hr, a higher heating value of 1,087.47 Btu/scf and 8,760 hours of operation per year.

Point 006:

Component	Gas Service	Heavy Oil	Light Oil	Water/Oil Service
Connectors	247	32	133	30
Flanges	247	32	133	30
Open-ended Lines	103	5	14	4
Pump Seals	0	0	32	4
Valves	475	32	225	37
Other*	3	0	0	0
VOC Content (wt. %)	35.63	100	100	100
Benzene Content (wt. %)	1.45×10^{-1}	1.26	1.26	1.26
Toluene Content (wt. %)	1.11×10^{-1}	2.99	2.99	2.99
Ethylbenzene (wt. %)	1.58×10^{-2}	9.52×10^{-1}	9.52×10^{-1}	9.52×10^{-1}
Xylenes Content (wt. %)	4.05×10^{-2}	2.56	2.56	2.56
n-Hexane Content (wt. %)	8.17×10^{-1}	6.56	6.56	6.56
2,2,4-Trimethylpentane Content (wt. %)	5.01×10^{-4}	1.11×10^{-2}	1.11×10^{-2}	1.11×10^{-2}
Methanol (wt. %)	---	6.75×10^{-2}	6.75×10^{-2}	6.75×10^{-2}

*Other equipment type includes compressors, pressure relief valves, relief valves, diaphragms, drains, dump arms, hatches, instrument meters, polish rods and vents

TOC Emission Factors (kg/hr-component):

Component	Gas Service	Heavy Oil	Light Oil	Water/Oil Service
Connectors	2.0E-04	7.5E-06	2.1E-04	1.1E-04
Flanges	3.9E-04	3.9E-07	1.1E-04	2.9E-06
Open-ended Lines	2.0E-03	1.4E-04	1.4E-03	2.5E-04
Pump Seals	2.4E-03	NA	1.3E-02	2.4E-05
Valves	4.5E-03	8.4E-06	2.5E-03	9.8E-05
Other	8.8E-03	3.2E-05	7.5E-03	1.4E-02

DRAFT

Source: EPA-453/R95-017 Table 2-4

Note that the emission limits included in this permit are derived by multiplying the equipment counts in the table above by a factor of 1.25 to accommodate other minor changes to the facility and to provide a conservative estimate of facility-wide emissions.

Compliance with emissions limits in this permit will be demonstrated by using the TOC emission factors listed in the table above with representative component counts, multiplied by the VOC content from the most recent extended gas analysis.

Point 009:

CAS #	Pollutant	Uncontrolled Emission Factors lb/bbl	Controlled Emission Factors lb/bbl	Source
	VOC	3.04	1.52×10^{-1}	ProMax & EPA Tanks 4.09d
71432	Benzene	1.58×10^{-2}	7.9×10^{-4}	
108883	Toluene	1.07×10^{-2}	5.35×10^{-4}	
110543	n-Hexane	9.02×10^{-2}	4.51×10^{-3}	

Note: The controlled emissions factors for this point are based on the enclosed combustion device control efficiency of 95%. The site specific VOC and HAP emission factors in the table above were developed using ProMax for flash emissions and EPA Tanks 4.09d for working and breathing emissions. The ProMax simulation is based on a representative sales gas sample obtained from an upstream facility (Hemberger 3-26-34-8-60) on September 13, 2012. The EPA Tanks simulation uses crude oil RVP 5 for the fluid basis and Denver as the location.

6) In accordance with C.R.S. 25-7-114.1, each Air Pollutant Emission Notice (APEN) associated with this permit is valid for a term of five years from the date it was received by the Division. A revised APEN shall be submitted no later than 30 days before the five-year term expires. Please refer to the most recent annual fee invoice to determine the APEN expiration date for each emissions point associated with this permit. For any questions regarding a specific expiration date call the Division at (303)-692-3150.

7) **Point 001:** This source is subject to 40 CFR, Part 60, **Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015** (See June 3, 2016 Federal Register posting - effective August 02, 2016). This rule has not yet been incorporated into Colorado Air Quality Control Commission's Regulation No. 6. A copy of the complete subpart is available on the EPA website at: https://www.gpo.gov/fdsys/pkg/FR-2016-06-03/pdf/2016-11971.pdf This unit is subject to requirements including, but not limited to the following:

   - **§60.5365a - Applicability and Designation of Affected Facilities**
     - **§60.5365a(g)(3) -** Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423a(c) but are not required to comply with §§60.5405a through 60.5407a and §§60.5410a(g) and 60.5415a(g).
   - **§60.5423a - Record keeping and reporting Requirements**
     - **§60.5423a(c) -** To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H2 S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H2 S expressed as sulfur.

8) **Point 006:** This source is subject to 40 CFR, Part 60, **Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction**

Commenced After September 18, 2015 (See June 3, 2016 Federal Register posting - effective August 02, 2016). This rule has not yet been incorporated into Colorado Air Quality Control Commission's Regulation No. 6. A copy of the complete subpart is available on the EPA website at: https://www.gpo.gov/fdsys/pkg/FR-2016-06-03/pdf/2016-11971.pdf

9) This permit fulfills the requirement to hold a valid permit reflecting the storage tank and associated control device per the Colorado Oil and Gas Conservation Commission rule 805b(2)(A) when applicable.

10) This facility is classified as follows:

Applicable Requirement	Status
Operating Permit	Synthetic Minor Source of: VOC, NOx, CO, benzene and total HAPs
NANSR	Synthetic Minor Source of: VOC and NOx
PSD	Synthetic Minor Source of: CO
MACT HH	Major Source Requirements: Not Applicable Area Source Requirements: Not Applicable
MACT DDDDD	Not applicable
NSPS Dc	Applicable to point 004
NSPS Db	Not applicable
NSPS Kb	Not applicable
NSPS KKK	Not applicable
NSPS LLL	Not applicable
NSPS OOOO	Not applicable
NSPS OOOOa	Applicable

11) Full text of the Title 40, Protection of Environment Electronic Code of Federal Regulations can be found at the website listed below:

http://ecfr.gpoaccess.gov/

Part 60: Standards of Performance for New Stationary Sources		
NSPS	60.1-End	Subpart A - Subpart KKKK
NSPS	Part 60, Appendixes	Appendix A - Appendix I
Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories		
MACT	63.1-63.599	Subpart A - Subpart Z
MACT	63.600-63.1199	Subpart AA - Subpart DDD
MACT	63.1200-63.1439	Subpart EEE - Subpart PPP
MACT	63.1440-63.6175	Subpart QQQ - Subpart YYYY
MACT	63.6580-63.8830	Subpart ZZZZ - Subpart MMMMM
MACT	63.8980-End	Subpart NNNNN - Subpart XXXXXX

Spark Ignition Engine APEN
Form APCD-201

Air Pollutant Emission Notice (APEN) and Application for Construction Permit

All sections of this APEN and application must be completed for both new and existing facilities, including APEN updates. An application with missing information may be determined incomplete and may be returned or result in longer application processing times. *You may be charged an additional APEN fee if the APEN is filled out incorrectly or is missing information and requires re-submittal.*

This APEN is to be used for spark ignition (e.g. gas-fired) reciprocating internal combustion engines (RICE). If your engine is a compression ignition engine (e.g. diesel-fired) or your emission unit does not fall into the RICE category, there may be a more specific APEN for your source (e.g. compression ignition engine, mining operations, asphalt plant, crusher, screen, etc.). In addition, the General APEN (Form APCD-200) is available if the specialty APEN options do not meet your reporting needs. A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website at: www.colorado.gov/cdphe/apcd.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Permit Number: GP02 **AIRS ID Number:** 123 / 9FC0 / 007

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 1 - Administrative Information

Company Name[1]: Outrigger DJ Operating LLC

Site Name: Makena Gas Plant

Site Location: NESE Sec 25 T8N R62W

Site Location County: Weld

NAICS or SIC Code: 237120

Mailing Address: *(Include Zip Code)* 1200 17th Street, Suite 900
Denver, CO 80202

Contact Person: Andrew Perdue

Phone Number: 720-361-2580

E-Mail Address[2]: aperdue@outriggerenergy.com

Portable Source Home Base:

[1] Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.

[2] Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

388606
383804
RECEIVED OCT - 5 2018 APCD Stationary Sources

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 007

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 2 - Requested Action

☑ **NEW permit OR newly-reported emission source** *(check one below)*

☑ STATIONARY source ☐ PORTABLE source

☐ Request coverage under a Construction Permit

☑ Request coverage under General Permit GP02[3] *(Natural Gas Only)*

If General Permit coverage is requested, the General Permit registration fee of $1,875 must be submitted along with the APEN filing fee.

- OR -

☐ **MODIFICATION to existing permit** *(check each box below that applies)*

☐ Change fuel or equipment ☐ Change company name[4] ☐ Add point to existing permit

☐ Change permit limit ☐ Transfer of ownership[5] ☐ Other *(describe below)*

- OR -

☐ **APEN submittal for update only *(Blank APENs will not be accepted)***

- ADDITIONAL PERMIT ACTIONS -

☐ **APEN submittal for permit-exempt/grandfathered source**

☐ **Notification of Alternate Operating Scenario (AOS) permanent replacement[6]**

Additional Info & Notes:

[3] Only one engine may be reported per APEN for GP02 coverage. Coverage under GP02 is voluntary.
[4] For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.
[5] For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.
[6] This does not apply to General Permit GP02, as it does not contain a provision for AOS *permanent* replacements.

Section 3 - General Information

Does this engine have a Company Equipment Identification No. *(e.g. ENG-1, Engine 3, etc.)*? Yes

If yes, provide the Company Equipment Identification No. C-1151

General description of equipment and purpose: Residue Gas Compression

For *existing* sources, operation began on:

For *new or reconstructed* sources, the projected start-up date is: TBD

Will this equipment be operated in any NAAQS nonattainment area? (http://www.colorado.gov/cdphe/attainment) ☑ Yes ☐ No

Normal Hours of Source Operation: 24 hours/day 7 days/week 52 weeks/year

Seasonal use percentage: Dec-Feb: 25 Mar-May: 25 June-Aug: 25 Sept-Nov: 25

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 007

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 4 - Engine Information

Engine Function: ☐ Primary and/or Peaking Power ☐ Emergency (max. 500 hrs/year) ☑ Compression
☐ Pump Jack ☐ Water Pump ☐ Other:

What is the maximum number of hours this engine will be used for emergency back-up power? ______ hours/year

Engine Make: Waukesha Engine Model: L-7044GSI Serial Number[7]: 5283705576

What is the maximum designed horsepower rating? 1680 hp

What is the maximum manufacturer's site-rating? 1680 hp 1253 kW

What is the engine Brake Specific Fuel Consumption at 100% Load? 8943 BTU/hp-hr

Engine Features:

Cycle Type: ☐ 2-Stroke ☑ 4-Stroke Combustion: ☐ Lean Burn ☑ Rich Burn

Aspiration: ☐ Natural ☑ Turbocharged

Is this engine equipped with an Air/Fuel ratio controller (AFRC)? ☑ Yes ☐ No

If yes, what type of AFRC is in use? ☑ O_2 Sensor (mV) ☐ NO_x Sensor (ppm) ☐ Other:

Is this engine equipped with a Low-NO_x design? ☐ Yes ☑ No

Engine Dates:

What is the manufactured date of this engine? 2018

What date was this engine ordered? TBD

What is the date this engine was first located to Colorado? TBD

What is the date this engine was first placed in service/operation? TBD

What is the date this engine commenced construction? TBD

What is the date this engine was last reconstructed or modified? TBD

Is this APEN reporting an AOS replacement engine? ☐ Yes ☑ No

If yes, provide the make, model, and serial number of the *old* engine below:

Engine Make: ______ Engine Model: ______ Serial Number: ______

[7] The serial number must be submitted if coverage under GP02 is requested.

Section 5 - Stack Information

Geographical Coordinates (Latitude/Longitude or UTM)
40.62922, -104.26171

Operator Stack ID No.	Discharge Height Above Ground Level (feet)	Temp. (°F)	Flow Rate (ACFM)	Velocity (ft/sec)
C-1151	TBD	1199	8527	TBD

Indicate the direction of the Stack outlet: *(check one)*

☑ Upward ☐ Downward ☐ Upward with obstructing raincap

☐ Horizontal ☐ Other (*describe*): ________

Indicate the stack opening and size: *(check one)*

☑ Circular Interior stack diameter (*inches*): TBD

☐ Square/Rectangle Interior stack diameter (*inches*): ____ Interior stack depth (*inches*): ____

☐ Other (*describe*): ________

Section 6 - Fuel Data and Throughput Information

Fuel Use Rate @ 100% Load (SCF/hour)	Actual Annual Fuel Use (MMSCF/year)	Requested Annual Permit Limit[8] (MMSCF/year)
13,816	--	121.03

From what year is the *actual annual amount?* ____

Indicate the type of fuel used[9]:

☐ Pipeline Natural Gas (*assumed fuel heating value of 1,020 BTU/scf*)

☑ Field Natural Gas Heating value: 1,087 BTU/scf

☐ Propane (*assumed fuel heating value of 2,300 BTU/scf*)

☐ Landfill Gas Heating Value: ____ BTU/scf

☐ Other (*describe*): ____ Heating Value (*give units*): ____

[8] Requested values will become permit limitations. Requested limit(s) should consider future process growth.
[9] If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

Section 7 - Emissions Inventory Information

Attach all emission calculations and emission factor documentation to this APEN form. The APCD website has a *Natural Gas Fired Engines Calculator* available to assist with emission calculations.

Is any emission control equipment or practice used to reduce emissions? ☐ Yes ☐ No

If yes, describe the control equipment AND state the overall control efficiency (% reduction):

Pollutant	Primary Control Equipment Description	Overall Requested Control Efficiency *(% reduction in emissions)*
TSP (PM)		
PM_{10}		
$PM_{2.5}$		
SO_X		
NO_X	NSCR/AFRC	~~97.9%~~ 97.52%
VOC	NSCR/AFRC	38.41%
CO	NSCR/AFRC	~~94.2%~~ 94.44%
Other:		

Use the following tables to report criteria and non-criteria pollutant emissions from source:
(*Use the data reported in Section 6 to calculate these emissions.*)

From what year is the following reported *actual annual emissions* data?

Criteria Pollutant Emissions Inventory							
Pollutant	Emission Factor			Actual Annual Emissions[10]		Requested Annual Permit Emission Limit(s)[8]	
	Uncontrolled Basis	Units	Source (AP-42, Mfg. etc)	Uncontrolled Emissions *(tons/year)*	Controlled Emissions *(tons/year)*	Uncontrolled Emissions *(tons/year)*	Controlled Emissions *(tons/year)*
TSP (PM)	0.0107326	lb/MMBtu	Mfg / AP-42	--	--	~~4.28~~ 0.71	~~4.28~~ 0.71
PM_{10}	0.0107326	lb/MMBtu	Mfg / AP-42	--	--	~~4.28~~ 0.71	~~4.28~~ 0.71
$PM_{2.5}$	0.0107326	lb/MMBtu	Mfg / AP-42	--	--	~~1.28~~ 0.71	~~1.28~~ 0.71
SO_X	0.000588	lb/MMBtu	AP-42	--	--	0.04	0.04
NO_X	~~10.28~~ 14.1	g/hp-hr	Manufacturer	--	--	~~214.18~~ 228.3	5.68
VOC	~~0.5~~ 0.982	g/hp-hr	Manufacturer	--	--	~~8.11~~ 13.2	8.11
CO	~~12~~ 12.16	g/hp-hr	Manufacturer	--	--	~~194.07~~ 204.4	11.36

HDS 01/24/19

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year? ☑ Yes ☐ No

If yes, please use the following table to report the non-criteria pollutant (HAP) emissions from source:

Non-Criteria Reportable Pollutant Emissions Inventory						
Chemical Name	Chemical Abstract Service (CAS) Number	Emission Factor			Actual Annual Emissions[10]	
		Uncontrolled Basis	Units	Source (AP-42, Mfg. etc)	Uncontrolled Emissions *(pounds/year)*	Controlled Emissions *(pounds/year)*
Formaldehyde	50000	0.05	g/hp-hr	Manufacturer	1,622.25 (PTE)	1,622.25 (PTE)
Acetaldehyde	75070	2.79E-3	lb/MMBtu	AP-42	367.20 (PTE)	367.20 (PTE)
Acrolein	107028	2.63E-3	lb/MMBtu	AP-42	346.2 (PTE)	346.2 (PTE)
Benzene	71432					
Other:	Methanol	3.06E-3	lb/MMBtu	AP-42	402.73 (PTE)	402.73 (PTE)

[8] Requested values will become permit limitations. Requested limit(s) should consider future process growth.
[10] Annual emissions fees will be based on actual controlled emissions reported. If source has not yet started operating, leave blank.

Redlines per email. HDS 01/11/19

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 007

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 8 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct. If this is a registration for coverage under General Permit GP02, I further certify that this source is and will be operated in full compliance with each condition of General Permit GP02.

10/4/18

Signature of Legally Authorized Person (not a vendor or consultant) Date

Andrew Perdue Senior Project Manager

Name (please print) Title

Check the appropriate box to request a copy of the:

- ☐ Draft permit prior to issuance
- ☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with $191.13 and the General Permit registration fee of $1,875, if applicable, to:

Colorado Department of Public Health and Environment
Air Pollution Control Division
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

Make check payable to:

Colorado Department of Public Health and Environment

For more information or assistance call:

Small Business Assistance Program
(303) 692-3175 or (303) 692-3148

APCD Main Phone Number
(303) 692-3150

Or visit the APCD website at:

https://www.colorado.gov/cdphe/apcd

Spark Ignition Engine APEN
Form APCD-201
Air Pollutant Emission Notice (APEN) and
Application for Construction Permit

All sections of this APEN and application must be completed for both new and existing facilities, including APEN updates. An application with missing information may be determined incomplete and may be returned or result in longer application processing times. *You may be charged an additional APEN fee if the APEN is filled out incorrectly or is missing information and requires re-submittal.*

This APEN is to be used for spark ignition (e.g. gas-fired) reciprocating internal combustion engines (RICE). If your engine is a compression ignition engine (e.g. diesel-fired) or your emission unit does not fall into the RICE category, there may be a more specific APEN for your source (e.g. compression ignition engine, mining operations, asphalt plant, crusher, screen, etc.). In addition, the General APEN (Form APCD-200) is available if the specialty APEN options do not meet your reporting needs. A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website at: www.colorado.gov/cdphe/apcd.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Permit Number: GP02 **AIRS ID Number:** 123 / 9FC0 / 008

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 1 - Administrative Information

Company Name[1]: Outrigger DJ Operating LLC

Site Name: Makena Gas Plant

Site Location: NESE Sec 25 T8N R62W

Site Location County: Weld

NAICS or SIC Code: 237120

Mailing Address: *(Include Zip Code)* 1200 17th Street, Suite 900
Denver, CO 80202

Contact Person: Andrew Perdue

Phone Number: 720-361-2580

E-Mail Address[2]: aperdue@outriggerenergy.com

Portable Source Home Base:

[1] Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.
[2] Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

388607

RECEIVED
OCT -5 2018
APCD
Stationary

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 008

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 2 - Requested Action

☑ **NEW permit OR newly-reported emission source** *(check one below)*

- ☑ STATIONARY source ☐ PORTABLE source
- ☐ Request coverage under a Construction Permit
- ☑ Request coverage under General Permit GP02[3] (*Natural Gas Only*)

If General Permit coverage is requested, the General Permit registration fee of $1,875 must be submitted along with the APEN filing fee.

- OR -

☐ **MODIFICATION to existing permit** *(check each box below that applies)*

☐ Change fuel or equipment	☐ Change company name[4]	☐ Add point to existing permit
☐ Change permit limit	☐ Transfer of ownership[5]	☐ Other *(describe below)*

- OR -

☐ **APEN submittal for update only *(Blank APENs will not be accepted)***

- ADDITIONAL PERMIT ACTIONS -

☐ APEN submittal for permit-exempt/grandfathered source

☐ Notification of Alternate Operating Scenario (AOS) permanent replacement[6]

Additional Info & Notes:

[3] Only one engine may be reported per APEN for GP02 coverage. Coverage under GP02 is voluntary.
[4] For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.
[5] For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.
[6] This does not apply to General Permit GP02, as it does not contain a provision for AOS *permanent* replacements.

Section 3 - General Information

Does this engine have a Company Equipment Identification No. (*e.g. ENG-1, Engine 3, etc.*)? Yes

If yes, provide the Company Equipment Identification No. C-1152

General description of equipment and purpose: Residue Gas Compression

For *existing* sources, operation began on:

For *new or reconstructed* sources, the projected start-up date is: TBD

Will this equipment be operated in any NAAQS nonattainment area? (http://www.colorado.gov/cdphe/attainment) ☑ Yes ☐ No

Normal Hours of Source Operation: 24 hours/day 7 days/week 52 weeks/year

Seasonal use percentage: Dec-Feb: 25 Mar-May: 25 June-Aug: 25 Sept-Nov: 25

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 008

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 4 - Engine Information

Engine Function: ☐ Primary and/or Peaking Power ☐ Emergency (max. 500 hrs/year) ☑ Compression

☐ Pump Jack ☐ Water Pump ☐ Other:

What is the maximum number of hours this engine will be used for emergency back-up power? hours/year

Engine Make: Waukesha Engine Model: L-7044GSI Serial Number[7]: 5283705726

What is the maximum designed horsepower rating? 1680 hp

What is the maximum manufacturer's site-rating? 1680 hp 1253 kW

What is the engine Brake Specific Fuel Consumption at 100% Load? 8943 BTU/hp-hr

Engine Features:

Cycle Type: ☐ 2-Stroke ☑ 4-Stroke Combustion: ☐ Lean Burn ☑ Rich Burn

Aspiration: ☐ Natural ☑ Turbocharged

Is this engine equipped with an Air/Fuel ratio controller (AFRC)? ☑ Yes ☐ No

If yes, what type of AFRC is in use? ☑ O_2 Sensor (mV) ☐ NO_X Sensor (ppm) ☐ Other:

Is this engine equipped with a Low-NO_X design? ☐ Yes ☑ No

Engine Dates:

What is the manufactured date of this engine? 2018

What date was this engine ordered? TBD

What is the date this engine was first located to Colorado? TBD

What is the date this engine was first placed in service/operation? TBD

What is the date this engine commenced construction? TBD

What is the date this engine was last reconstructed or modified? TBD

Is this APEN reporting an AOS replacement engine? ☐ Yes ☑ No

If yes, provide the make, model, and serial number of the *old* engine below:

Engine Make: Engine Model: Serial Number:

[7] The serial number must be submitted if coverage under GP02 is requested.

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 008

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 5 - Stack Information

Geographical Coordinates *(Latitude/Longitude or UTM)*
40.62922, -104.26171

Operator Stack ID No.	Discharge Height Above Ground Level *(feet)*	Temp. *(°F)*	Flow Rate *(ACFM)*	Velocity *(ft/sec)*
C-1152	TBD	1199	8527	TBD

Indicate the direction of the Stack outlet: *(check one)*

☑ Upward ☐ Downward ☐ Upward with obstructing raincap

☐ Horizontal ☐ Other (*describe*): ______

Indicate the stack opening and size: *(check one)*

☑ Circular Interior stack diameter (*inches*): TBD

☐ Square/Rectangle Interior stack diameter (*inches*): ______ Interior stack depth (*inches*): ______

☐ Other (*describe*): ______

Section 6 - Fuel Data and Throughput Information

Fuel Use Rate @ 100% Load *(SCF/hour)*	Actual Annual Fuel Use *(MMSCF/year)*	Requested Annual Permit Limit[8] *(MMSCF/year)*
13,816	--	121.03

From what year is the *actual annual amount*? ______

Indicate the type of fuel used[9]:

☐ Pipeline Natural Gas (*assumed fuel heating value of 1,020 BTU/scf*)

☑ Field Natural Gas Heating value: 1,087 BTU/scf

☐ Propane (*assumed fuel heating value of 2,300 BTU/scf*)

☐ Landfill Gas Heating Value: ______ BTU/scf

☐ Other (*describe*): ______ Heating Value (*give units*): ______

[8] Requested values will become permit limitations. Requested limit(s) should consider future process growth.

[9] If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

Section 7 - Emissions Inventory Information

Attach all emission calculations and emission factor documentation to this APEN form. The APCD website has a *Natural Gas Fired Engines Calculator* available to assist with emission calculations.

Is any emission control equipment or practice used to reduce emissions? ☐ Yes ☐ No

If yes, describe the control equipment AND state the overall control efficiency (% reduction):

Pollutant	Primary Control Equipment Description	Overall Requested Control Efficiency *(% reduction in emissions)*
TSP (PM)		
PM_{10}		
$PM_{2.5}$		
SO_X		
NO_X	NSCR/AFRC	~~97.3%~~ 93.52%
VOC	NSCR/AFRC	38.41%
CO	NSCR/AFRC	~~94.2%~~ 94.44%
Other:		

Use the following tables to report criteria and non-criteria pollutant emissions from source:
(*Use the data reported in Section 6 to calculate these emissions.*)

From what year is the following reported *actual annual emissions* data?

Criteria Pollutant Emissions Inventory							
Pollutant	Emission Factor			Actual Annual Emissions[10]		Requested Annual Permit Emission Limit(s)[8]	
	Uncontrolled Basis	Units	Source (AP-42, Mfg. etc)	Uncontrolled Emissions *(tons/year)*	Controlled Emissions *(tons/year)*	Uncontrolled Emissions *(tons/year)*	Controlled Emissions *(tons/year)*
TSP (PM)	0.0107386	lb/MMBtu	Mfg / AP-42	–	–	~~1.20~~ 0.71	~~1.20~~ 0.71
PM_{10}	0.0107386	lb/MMBtu	Mfg / AP-42	–	–	~~1.20~~ 0.71	~~1.20~~ 0.71
$PM_{2.5}$	0.0107386	lb/MMBtu	Mfg / AP-42	–	–	~~1.20~~ 0.71	~~1.20~~ 0.71
SO_X	0.000588	lb/MMBtu	AP-42	–	–	0.04	0.04
NO_X	~~10.26~~ 14.1	g/hp-hr	Manufacturer	–	–	~~214.14~~ 218.7	5.68
VOC	~~0.5~~ 0.852	g/hp-hr	Manufacturer	–	–	~~8.44~~ 13.2	8.11
CO	~~12~~ 12.6	g/hp-hr	Manufacturer	–	–	~~194.07~~ 204.4	11.36

HDS 01/24/19

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year? ☑ Yes ☐ No

If yes, please use the following table to report the non-criteria pollutant (HAP) emissions from source:

Non-Criteria Reportable Pollutant Emissions Inventory						
Chemical Name	Chemical Abstract Service (CAS) Number	Emission Factor			Actual Annual Emissions[10]	
		Uncontrolled Basis	Units	Source (AP-42, Mfg. etc)	Uncontrolled Emissions *(pounds/year)*	Controlled Emissions *(pounds/year)*
Formaldehyde	50000	0.05	g/hp-hr	Manufacturer	1,622.25 (PTE)	1,622.25 (PTE)
Acetaldehyde	75070	2.79E-3	lb/MMBtu	AP-42	367.20 (PTE)	367.20 (PTE)
Acrolein	107028	2.63E-3	lb/MMBtu	AP-42	346.2 (PTE)	346.2 (PTE)
Benzene	71432					
Other:	Methanol	3.06E-3	lb/MMBtu	AP-42	402.73 (PTE)	402.73 (PTE)

[8] Requested values will become permit limitations. Requested limit(s) should consider future process growth.
[10] Annual emissions fees will be based on actual controlled emissions reported. If source has not yet started operating, leave blank.

Redlines per attached email. HDS 01/11/19

Permit Number: GP02 AIRS ID Number: 123 /9FC0/ 008

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 8 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct. If this is a registration for coverage under General Permit GP02, I further certify that this source is and will be operated in full compliance with each condition of General Permit GP02.

[signature] 10/4/18

Signature of Legally Authorized Person (not a vendor or consultant) Date

Andrew Perdue Senior Project Manager

Name (please print) Title

Check the appropriate box to request a copy of the:

- ☐ Draft permit prior to issuance
- ☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with $191.13 and the General Permit registration fee of $1,875, if applicable, to:

Colorado Department of Public Health and Environment
Air Pollution Control Division
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

Make check payable to:

Colorado Department of Public Health and Environment

For more information or assistance call:

Small Business Assistance Program
(303) 692-3175 or (303) 692-3148

APCD Main Phone Number
(303) 692-3150

Or visit the APCD website at:

https://www.colorado.gov/cdphe/apcd

Spark Ignition Engine APEN
Form APCD-201

Air Pollutant Emission Notice (APEN) and
Application for Construction Permit

All sections of this APEN and application must be completed for both new and existing facilities, including APEN updates. An application with missing information may be determined incomplete and may be returned or result in longer application processing times. *You may be charged an additional APEN fee if the APEN is filled out incorrectly or is missing information and requires re-submittal.*

This APEN is to be used for spark ignition (e.g. gas-fired) reciprocating internal combustion engines (RICE). If your engine is a compression ignition engine (e.g. diesel-fired) or your emission unit does not fall into the RICE category, there may be a more specific APEN for your source (e.g. compression ignition engine, mining operations, asphalt plant, crusher, screen, etc.). In addition, the General APEN (Form APCD-200) is available if the specialty APEN options do not meet your reporting needs. A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website at: www.colorado.gov/cdphe/apcd.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Permit Number: GP02 **AIRS ID Number:** 123 /9FC0/ 010

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 1 - Administrative Information

Company Name[1]: Outrigger DJ Operating LLC

Site Name: Makena Gas Plant

Site Location: NESE Sec 25 T8N R62W

Site Location County: Weld

NAICS or SIC Code: 237120

Mailing Address: *(Include Zip Code)* 1200 17th Street, Suite 900
Denver, CO 80202

Contact Person: Andrew Perdue

Phone Number: 720-361-2580

E-Mail Address[2]: aperdue@outriggerenergy.com

Portable Source Home Base:

[1] Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.

[2] Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

388608

RECEIVED
OCT - 5 2018
APCD
Stationary
Sources

Permit Number: GP02 AIRS ID Number: 123 9FC0/010

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 2 - Requested Action

☑ NEW permit OR newly-reported emission source *(check one below)*

☑ STATIONARY source ☐ PORTABLE source

☐ Request coverage under a Construction Permit

☑ Request coverage under General Permit GP02[3] (*Natural Gas Only*)

If General Permit coverage is requested, the General Permit registration fee of $1,875 must be submitted along with the APEN filing fee.

- OR -

☐ MODIFICATION to existing permit *(check each box below that applies)*

☐ Change fuel or equipment ☐ Change company name[4] ☐ Add point to existing permit

☐ Change permit limit ☐ Transfer of ownership[5] ☐ Other *(describe below)*

- OR -

☐ APEN submittal for update only ***(Blank APENs will not be accepted)***

- ADDITIONAL PERMIT ACTIONS -

☐ APEN submittal for permit-exempt/grandfathered source

☐ Notification of Alternate Operating Scenario (AOS) permanent replacement[6]

Additional Info & Notes:

[3] Only one engine may be reported per APEN for GP02 coverage. Coverage under GP02 is voluntary.
[4] For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.
[5] For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.
[6] This does not apply to General Permit GP02, as it does not contain a provision for AOS *permanent* replacements.

Section 3 - General Information

Does this engine have a Company Equipment Identification No. (*e.g. ENG-1, Engine 3, etc.*)? Yes

If yes, provide the Company Equipment Identification No. C-1153

General description of equipment and purpose: Inlet Compression

For *existing* sources, operation began on:

For *new or reconstructed* sources, the projected start-up date is: TBD

Will this equipment be operated in any NAAQS nonattainment area? ☑ Yes ☐ No
(http://www.colorado.gov/cdphe/attainment)

Normal Hours of Source Operation: 24 hours/day 7 days/week 52 weeks/year

Seasonal use percentage: Dec-Feb: 25 Mar-May: 25 June-Aug: 25 Sept-Nov: 25

Permit Number: GP02 AIRS ID Number: 123 9FC0 / 010

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 4 - Engine Information

Engine Function: ☐ Primary and/or Peaking Power ☐ Emergency (max. 500 hrs/year) ☑ Compression ☐ Pump Jack ☐ Water Pump ☐ Other:

What is the maximum number of hours this engine will be used for emergency back-up power? ______ hours/year

Engine Make: Waukesha Engine Model: L-7044GSI Serial Number[7]: 5283704171

What is the maximum designed horsepower rating? 1680 hp

What is the maximum manufacturer's site-rating? 1680 hp 1253 kW

What is the engine Brake Specific Fuel Consumption at 100% Load? 9943 BTU/hp-hr

Redline per application. HDS 01/11/19

Engine Features:

Cycle Type: ☐ 2-Stroke ☑ 4-Stroke Combustion: ☐ Lean Burn ☑ Rich Burn

Aspiration: ☐ Natural ☑ Turbocharged

Is this engine equipped with an Air/Fuel ratio controller (AFRC)? ☑ Yes ☐ No

If yes, what type of AFRC is in use? ☑ O_2 Sensor (mV) ☐ NO_X Sensor (ppm) ☐ Other:

Is this engine equipped with a Low-NO_X design? ☐ Yes ☑ No

Engine Dates:

What is the manufactured date of this engine? 2018

What date was this engine ordered? TBD

What is the date this engine was first located to Colorado? TBD

What is the date this engine was first placed in service/operation? TBD

What is the date this engine commenced construction? TBD

What is the date this engine was last reconstructed or modified? TBD

Is this APEN reporting an AOS replacement engine? ☐ Yes ☑ No

If yes, provide the make, model, and serial number of the *old* engine below:

Engine Make: ______ Engine Model: ______ Serial Number: ______

[7] The serial number must be submitted if coverage under GP02 is requested.

Permit Number: GP02 AIRS ID Number: 123 /9FCD/ 010

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 5 - Stack Information

Geographical Coordinates *(Latitude/Longitude or UTM)*
40.62922, -104.26171

Operator Stack ID No.	Discharge Height Above Ground Level *(feet)*	Temp. *(°F)*	Flow Rate *(ACFM)*	Velocity *(ft/sec)*
C-1153	TBD	1217	TBD	TBD

Indicate the direction of the Stack outlet: *(check one)*

☑ Upward ☐ Downward ☐ Upward with obstructing raincap

☐ Horizontal ☐ Other (*describe*):

Indicate the stack opening and size: *(check one)*

☑ Circular Interior stack diameter (*inches*): TBD

☐ Square/Rectangle Interior stack diameter (*inches*): Interior stack depth (*inches*):

☐ Other (*describe*):

Section 6 - Fuel Data and Throughput Information

Fuel Use Rate @ 100% Load *(SCF/hour)*	Actual Annual Fuel Use *(MMSCF/year)*	Requested Annual Permit Limit[8] *(MMSCF/year)*
~~12,880~~ 13,816	--	~~112.83~~ 121.03

Redline per application.

HDS 01/11/19

From what year is the *actual annual amount*?

Indicate the type of fuel used[9]:

☐ Pipeline Natural Gas (*assumed fuel heating value of 1,020 BTU/scf*)

☑ Field Natural Gas Heating value: 1,087 BTU/scf

☐ Propane (*assumed fuel heating value of 2,300 BTU/scf*)

☐ Landfill Gas Heating Value: BTU/scf

☐ Other (*describe*): Heating Value (*give units*):

[8] Requested values will become permit limitations. Requested limit(s) should consider future process growth.

[9] If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

Permit Number: GP02 AIRS ID Number: 123 /9FCD/ 010

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 7 - Emissions Inventory Information

Attach all emission calculations and emission factor documentation to this APEN form. The APCD website has a *Natural Gas Fired Engines Calculator* available to assist with emission calculations.

Is any emission control equipment or practice used to reduce emissions? ☐ Yes ☐ No

If yes, describe the control equipment AND state the overall control efficiency (% reduction):

Pollutant	Primary Control Equipment Description	Overall Requested Control Efficiency *(% reduction in emissions)*
TSP (PM)		
PM_{10}		
$PM_{2.5}$		
SO_X		
NO_X	NSCR/AFRC	97.5%
VOC	NSCR/AFRC	~~82.4%~~ 38.41%
CO	NSCR/AFRC	94.4%
Other:		

Use the following tables to report criteria and non-criteria pollutant emissions from source:
(Use the data reported in Section 6 to calculate these emissions.)

From what year is the following reported *actual annual emissions* data?

Criteria Pollutant Emissions Inventory							
Pollutant	Emission Factor			Actual Annual Emissions[10]		Requested Annual Permit Emission Limit(s)[8]	
	Uncontrolled Basis	Units	Source (AP-42, Mfg. etc)	Uncontrolled Emissions *(tons/year)*	Controlled Emissions *(tons/year)*	Uncontrolled Emissions *(tons/year)*	Controlled Emissions *(tons/year)*
TSP (PM)	0.0107326	lb/MMBtu	~~Mfg~~ / AP-42	--	--	~~1.10~~ 0.71	~~1.10~~ 0.71
PM_{10}	0.0107326	lb/MMBtu	~~Mfg~~ / AP-42	--	--	~~1.10~~ 0.71	~~1.10~~ 0.71
$PM_{2.5}$	0.0107326	lb/MMBtu	~~Mfg~~ / AP-42	--	--	~~1.10~~ 0.71	~~1.10~~ 0.71
SO_X	0.000588	lb/MMBtu	AP-42	--	--	0.04 *	0.04 *
NO_X	14.10	g/hp-hr	Manufacturer	--	--	228.74 *	5.68 *
VOC	~~0.74~~ 0.812	g/hp-hr	Manufacturer	--	--	~~12.00~~ 13.2	8.11 *
CO	12.60	g/hp-hr	Manufacturer	--	--	204.40 *	11.36 *

HDS 01/24/19

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year? ☑ Yes ☐ No

If yes, please use the following table to report the non-criteria pollutant (HAP) emissions from source:

Non-Criteria Reportable Pollutant Emissions Inventory						
Chemical Name	Chemical Abstract Service (CAS) Number	Emission Factor			Actual Annual Emissions[10]	
		Uncontrolled Basis	Units	Source (AP-42, Mfg. etc)	Uncontrolled Emissions *(pounds/year)*	Controlled Emissions *(pounds/year)*
Formaldehyde	50000	0.05 *	g/hp-hr	Manufacturer	1,622.25 (PTE) *	1,622.25 (PTE) *
Acetaldehyde	75070	2.79E-3	lb/MMBtu	AP-42	367.2 (PTE)	367.2 (PTE)
Acrolein	107028	2.63E-3	lb/MMBtu	AP-42	346.2 (PTE)	346.2 (PTE)
Benzene	71432					
Other:	Methanol	3.06E-3	lb/MMBtu	AP-42	402.7 (PTE)	402.7 (PTE)

Redlines per attached email.

[8] Requested values will become permit limitations. Requested limit(s) should consider future process growth.

[10] Annual emissions fees will be based on actual controlled emissions reported. If source has not yet started operating, leave blank.

HDS 01/11/19

Permit Number: GP02 AIRS ID Number: 123/9FC0/010

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 8 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct. If this is a registration for coverage under General Permit GP02, I further certify that this source is and will be operated in full compliance with each condition of General Permit GP02.

Signature of Legally Authorized Person (not a vendor or consultant) Date: 10/4/18

Andrew Perdue — Senior Project Manager

Name (please print) Title

Check the appropriate box to request a copy of the:

- ☐ Draft permit prior to issuance
- ☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with $191.13 and the General Permit registration fee of $1,875, if applicable, to:

Colorado Department of Public Health and Environment
Air Pollution Control Division
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

Make check payable to:

Colorado Department of Public Health and Environment

For more information or assistance call:

Small Business Assistance Program
(303) 692-3175 or (303) 692-3148

APCD Main Phone Number
(303) 692-3150

Or visit the APCD website at:

https://www.colorado.gov/cdphe/apcd

Appendix C

Alliance
SOURCE TESTING

Location --
Source --
Project No. --
Run No.
Method --

Meter Pressure (Pm), in. Hg

$$Pm = Pb + \frac{\Delta H}{13.6}$$

where,

Pb	--	= barometric pressure, in. Hg
ΔH	0.000	= pressure differential of orifice, in H_2O
Pm	--	= in. Hg

Absolute Stack Gas Pressure (Ps), in. Hg

$$Ps = Pb + \frac{Pg}{13.6}$$

where,

Pb	--	= barometric pressure, in. Hg
Pg	--	= static pressure, in. H_2O
Ps	--	= in. Hg

Standard Meter Volume (Vmstd), dscf

$$Vmstd = \frac{17.647 \times Y \times Vm \times Pm}{Tm}$$

where,

Y	0.000	= meter correction factor
Vm	--	= meter volume, cf
Pm	--	= absolute meter pressure, in. Hg
Tm	--	= absolute meter temperature, °R
Vmstd	--	= dscf

Standard Wet Volume (Vwstd), scf

$$Vwstd = 0.04707 \times Vlc$$

where,

Vlc	--	= volume of H2O collected, ml
Vwstd	--	= scf

Moisture Fraction (BWSsat), dimensionless (theoretical at saturated conditions)

$$BWSsat = \frac{10^{6.37 - \left(\frac{2,827}{Ts + 365}\right)}}{Ps}$$

where,

Ts	--	= stack temperature, °F
Ps	--	= absolute stack gas pressure, in. Hg
BWSsat	--	= dimensionless

Moisture Fraction (BWSmsd), dimensionless (measured)

$$BWS = \frac{Vwstd}{(Vwstd + Vmstd)}$$

where,

Vwstd	--	= standard wet volume, scf
Vmstd	--	= standard meter volume, dscf
BWS	--	= dimensionless

Moisture Fraction (BWS), dimensionless

$$BWS = BWSmsd \text{ unless } BWSsat < BWSmsd$$

where,

BWSsat	--	= moisture fraction (theoretical at saturated conditions)
BWSmsd	--	= moisture fraction (measured)
BWS	--	= dimensionless

Molecular Weight (DRY) (Md), lb/lb-mole

$$Md = (0.44 \times \% CO_2) + (0.32 \times \% O_2) + (0.28 (100 - \% CO_2 - \% O_2))$$

where,

CO_2	--	= carbon dioxide concentration, %
O_2	--	= oxygen concentration, %
Md	--	= lb/lb mol

Molecular Weight (WET) (Ms), lb/lb-mole

$$Ms = Md\ (1 - BWS) + 18\ (BWS)$$

where,

Md	--	= molecular weight (DRY), lb/lb mol
BWS	--	= moisture fraction, dimensionless
Ms	--	= lb/lb mol

Alliance
SOURCE TESTING

Location --
Source --
Project No. --
Run No.
Method --

Average Velocity (Vs), ft/sec

$$Vs = 85.49 \times Cp \times (\Delta P^{1/2})\,avg \times \sqrt{\frac{Ts}{Ps \times Ms}}$$

where,

Cp	--	= pitot tube coefficient
$\Delta P^{1/2}$	--	= velocity head of stack gas, (in. H2O)$^{1/2}$
Ts	--	= absolute stack temperature, °R
Ps	--	= absolute stack gas pressure, in. Hg
Ms	--	= molecular weight of stack gas, lb/lb mol
Vs	--	= ft/sec

Average Stack Gas Flow at Stack Conditions (Qa), acfm

$$Qa = 60 \times Vs \times As$$

where,

Vs	--	= stack gas velocity, ft/sec
As	--	= cross-sectional area of stack, ft^2
Qa	--	= acfm

Average Stack Gas Flow at Standard Conditions (Qsw), scfm

$$Qsw = 17.647 \times Qa \times \frac{Ps}{Ts}$$

where,

Qa	--	= average stack gas flow at stack conditions, acfm
Ps	--	= absolute stack gas pressure, in. Hg
Ts	--	= absolute stack temperature, °R
Qsw	--	= scfm

Average Stack Gas Flow at Standard Conditions (Qsd), dscfm

$$Qsd = 17.647 \times Qa \times (1 - BWS) \times \frac{Ps}{Ts}$$

where,

Qa	--	= average stack gas flow at stack conditions, acfm
BWS	--	= moisture fraction
Ps	--	= absolute stack gas pressure, in. Hg
Ts	--	= absolute stack temperature, °R
Qsd	--	= dscfm

Alliance SOURCE TESTING

Location:	--
Source:	--
Project No.:	--
Run No. /Method	Run 1 - Method

Stack Gas Volumetric Flow Rate (Qs), dscfm

$$Qs = \frac{F_R \times F_{HV} \times F_d \times \left(\frac{20.9}{20.9 - C_{O2}}\right)}{1.0E+06 \times 60}$$

where,

F_R -- = fuel rate, scfh
F_{HV} -- = fuel heating value, Btu/scf
F_d -- = fuel factor, dscf/MMBtu
C_{O2} -- = oxygen concentration, %
Qs -- = dscfm

Target 1 - Concentration Adjusted for Analyzer Drift, ppmvd

$$C_{CO} = (C_{obs} - C_o) \times \left(\frac{C_{MA}}{(C_M - C_o)}\right)$$

where,

C_{obs} -- = average analyzer value during test, ppmvd
C_o -- = average of pretest & posttest zero responses, ppmvd
C_{MA} -- = actual concentration of calibration gas, ppmvd
C_M -- = average of pretest & posttest calibration responses, ppmvd
C_{CO} -- = concentration, ppmvd

Target 1 - Outlet Concentration, ppmvd

$$C_{T1d} = \frac{C_{T1w}}{1 - BWS}$$

where,

CT1w -- = T1 concentration, ppmvw
BWS -- = moisture fraction, unitless
CT1d -- = ppmvd

Target 1 - Outlet Concentration, ppmvd @ 15% O2

$$C_{T1c} = C_{T1}\ x\ \frac{20.9 - C_{O2c}}{20.9 - C_{O2}}$$

where,

CT1 -- = T1 concentration, ppmvd
C_{O2c} 15.0 = Desired O2 correction concentration, %
C_{O2} -- = O_2 concentration, %
CT1c3 -- = ppmvd @ 3% O_2

Target 1 - Outlet Emission Rate, lb/hr

$$ER_{T1} = \frac{C_{T1} \times MW \times Qs \times 60 \times 28.32}{24.04 \times 1.0E+06 \times 454}$$

where,

CT1 -- = T1 concentration, ppmvd
MW -- = molecular weight, g/g-mole
Qs -- = stack gas volumetric flow rate at standard conditions, dscfm
ER T1 -- = lb/hr

Target 1 - Outlet Emisson Factor, lb/MMBtu (O2d)

$$EF_{T1\ O2d} = C_{T1} \times K \times F_d \times \frac{20.9}{20.9 - C_{O2}}$$

where,

CT1 -- = T1 concentration, ppmvd
K 2.5971E-09 = constant, lb/dscf · ppm

Location: --

F_d	--	= fuel factor, dscf/MMBtu
C_{O2}	--	= O_2 concentration, %
EFT1 O2d	--	= lb/MMBtu

Target 1 - Outlet Emisson Factor, lb/MMBtu (CO2)

$$EF_{T1\,CO2d} = C_{T1} \times K \times F_c \times \frac{100}{C_{CO2}}$$

CT1	--	= T1 concentration, ppmvd
K	2.5971E-09	= constant, lb/dscf · ppm
F_c	--	= fuel factor, dscf/MMBtu
C_{CO2}	--	= CO_2 concentration, %
EFT1C O2d	--	= lb/MMBtu

Sample Calculations

$$\text{(lb/hr)} = [\text{analyte conc. (ppmvd)}]*(F_{DSCFM})*(1.556\ E\text{-}7)*(\text{MW analyte})$$

$$\text{emissions (tpy)} = \frac{[\text{emissions (lb/hr)}] * [8{,}760\ \text{(hours/year)}]}{[2{,}000\ \text{(pounds/ton)}]}$$

$$\text{emissions (g/bhp-hr)} = \frac{[\text{emissions (lb/hr)}] * [454\ \text{(g/lb)}]}{[\text{engine load (bhp)}]}$$

$$\text{emissions (lb/mo)} = [\text{emissions (lb/hr)}] * [24\ \text{hr/day}] * [31\ \text{day/mo}]$$

$$\text{VOC (ppmvd as propane)} = \left| \frac{1.9\ C13}{1 + \exp((0\text{-}C13)/0.2))} + \frac{2.4\ C14}{1 + \exp((0\text{-}C14)/0.2))} + 3\ C15 + \frac{2.85\ C16}{1 + \exp((0\text{-}C16)/0.2))} + \frac{4\ C17}{1 + \exp((0\text{-}C17)/0.2))} \right| * \frac{1}{1\text{-}(C7/100)} * \frac{1}{3}$$

<u>Variables and Abbreviations</u>

conc - concentration

F_{DSCFM} - gas flow (dry standard cubic feet per minute, where standard = 29.92 inches Hg and 68°F)

lb/hr - pounds per hour

tpy - tons per year

ppmvd - parts per million, dry volume basis

g/bhp-hr - grams per brake horsepower-hour

lb/mo - pounds per month

MW - molecular weight (g/mol)

C7 - moisutre concentration (%vd)

C13 - ethylene concnetration (ppmvw)

C14 - acetylene concentration (ppmvw)

C15 - propane concentration (ppmvw)

C16 - propylene concentration (ppmvw)

C17 - butane concentration

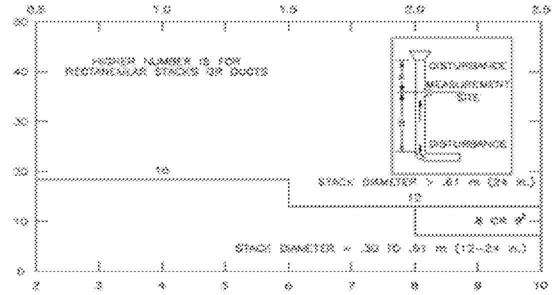
Appendix D

Method 1 Data

Location --
Source --
Project No. --
Date:

Stack Parameters

Duct Orientation:		
Duct Design:		
Distance from Far Wall to Outside of Port:	--	in
Nipple Length:	--	in
Depth of Duct:	--	in
Width of Duct:	--	in
Cross Sectional Area of Duct:	--	ft^2
Equivalent Diameter:	--	in
No. of Test Ports:	--	
Distance A:	--	ft
Distance A Duct Diameters:	--	(must be > 0.5)
Distance B:	--	ft
Distance B Duct Diameters:	--	(must be > 2)
Minimum Number of Traverse Points:	0	
Actual Number of Traverse Points:		



DUCT

LOCATION OF TRAVERSE POINTS

Number of traverse points on a diameter

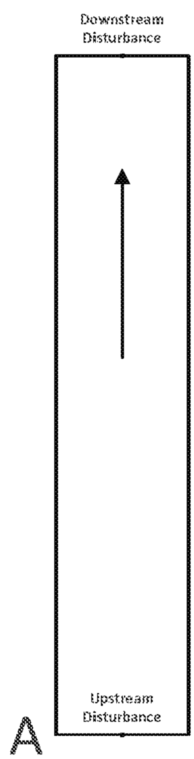
	2	3	4	5	6	7	8	9	10	11	12
1	25.0	16.7	12.5	10.0	8.3	7.1	6.3	5.6	5.0	4.5	4.2
2	75.0	50.0	37.5	30.0	25.0	21.4	18.8	16.7	15.0	13.6	12.5
3	--	83.3	62.5	50.0	41.7	35.7	31.3	27.8	25.0	31.8	20.8
4	--	--	87.5	70.0	58.3	50.0	43.8	38.9	35.0	22.7	29.2
5	--	--	--	90.0	75.0	64.3	56.3	50.0	45.0	40.9	37.5
6	--	--	--	--	91.7	78.6	68.8	61.1	55.0	50.0	45.8
7	--	--	--	--	--	92.9	81.3	72.2	65.0	59.1	54.2
8	--	--	--	--	--	--	93.8	83.3	75.0	68.2	62.5
9	--	--	--	--	--	--	--	94.4	85.0	77.3	70.8
10	--	--	--	--	--	--	--	--	95.0	86.4	79.2
11	--	--	--	--	--	--	--	--	--	95.5	87.5
12	--	--	--	--	--	--	--	--	--	--	95.8

**Percent of stack diameter from inside wall to traverse point.*

Traverse Point	% of Diameter	Distance from inside wall	Distance from outside of port
1	--	--	--
2	--	--	--
3	--	--	--
4	--	--	--
5	--	--	--
6	--	--	--
7	--	--	--
8	--	--	--
9	--	--	--
10	--	--	--
11	--	--	--
12	--	--	--

Stack Diagram
A = -- ft.
B = -- ft.
Depth of Duct = -- in.

Cross Sectional Area



Field Data
Cyclonic Flow Check

Location --
Source --
Project No. --
Date

Sample Point	Angle ($\Delta P=0$)
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
Average	--

Alliance
SOURCE TESTING

Location --
Source --
Project No. --

Run No.	1		2		3	
Date			--		--	
Status	VALID		VALID		VALID	
Start Time						
Stop Time						
Leak Check						
Traverse Point	Δ P (in. WC)	Ts (°F)	Δ P (in. WC)	Ts (°F)	Δ P (in. WC)	Ts (°F)

		1	2	3	Average
Square Root of ΔP, (in. WC)$^{1/2}$	(ΔP)$^{1/2}$	--	--	--	--
Average ΔP, in. WC	(ΔP)	--	--	--	--
Pitot Tube Coefficient	(Cp)	--	--	--	--
Barometric Pressure, in. Hg	(Pb)	--	--	--	--
Static Pressure, in. WC	(Pg)	--	--	--	--
Stack Pressure, in. Hg	(Ps)	--	--	--	--
Average Temperature, °F	(Ts)	--	--	--	--
Average Temperature, °R	(Ts)	--	--	--	--
Moisture Fraction	(BWS)	--	--	--	--
O2 Concentration, %	(O2)	--	--	--	--
CO2 Concentration, %	(CO2)	--	--	--	--
Molecuar Weight, lb/lb-mole (dry)	(Md)	--	--	--	--
Molecuar Weight, lb/lb-mole (wet)	(Ms)	--	--	--	--
Velocity, ft/sec	(Vs)	--	--	--	--
VFR at stack conditions, acfm	(Qa)	--	--	--	--
VFR at standard conditions, scfh	(Qsw)	--	--	--	--
VFR at standard conditions, scfm	(Qsw)	--	--	--	--
VFR at standard conditions, dscfm	(Qsd)	--	--	--	--

Location --
Source --
Project No. --

	O_2 Data			CO_2 Data		
	Date/Time			Date/Time		
Make/Model/SN	--	--	--	--	--	--
Parameter	Cylinder ID	Cylinder Concentration, %	Analyzer Concentration, %	Cylinder ID	Cylinder Concentration, %	Analyzer Concentration, %
Zero Gas						
High Range Gas						
Mid Range Gas						
Concentration Span, %	--			--		
Accuracy, %	--			--		

	Date/Time			Date/Time		
Make/Model/SN	--	--	--	--	--	--
Parameter	Cylinder ID	Cylinder Concentration, %	Analyzer Concentration, %	Cylinder ID	Cylinder Concentration, %	Analyzer Concentration, %
Zero Gas	--	--		--	--	
High Range Gas	--	--		--	--	
Mid Range Gas	--	--		--	--	
Concentration Span, %	--			--		
Accuracy, %	--			--		

	Date/Time			Date/Time		
Make/Model/SN	--	--	--	--	--	--
Parameter	Cylinder ID	Cylinder Concentration, %	Analyzer Concentration, %	Cylinder ID	Cylinder Concentration, %	Analyzer Concentration, %
Zero Gas	--	--		--	--	
High Range Gas	--	--		--	--	
Mid Range Gas	--	--		--	--	
Concentration Span, %	--			--		
Accuracy, %	--			--		

Alliance
SOURCE TESTING

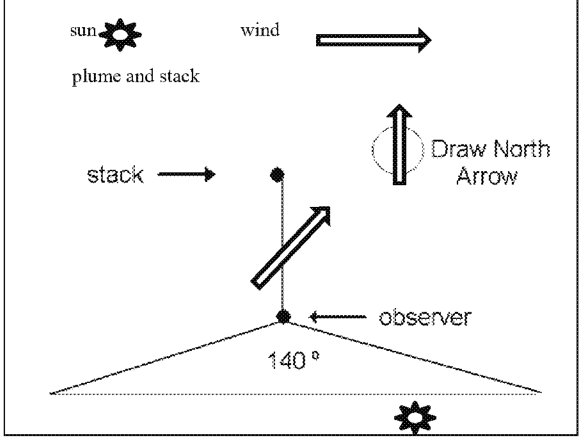
Location --
Source --
Project No. --

Run No.		**1**	**2**	**3**
Date				
Status		VALID	VALID	VALID
Start Time				
End Time				
Run Time, min	**(θ)**			
Meter ID				
Meter Correction Factor	**(Y)**			
Orifice Calibration Value	**(ΔH @)**			
Max Vacuum, in. Hg				
Post Leak Check, cfm (at max vac.)				
Meter Volume, ft^3				
Time				
0				
5				
10				
15				
20				
25				
30				
35				
40				
45				
50				
55				
60				
Total Meter Volume, ft^3	**(Vm)**	--	--	--
Temperature, °F				
Time		**Meter** / **Imp. Exit**	**Meter** / **Imp. Exit**	**Meter** / **Imp. Exit**
0		/	/	/
5		/	/	/
10		/	/	/
15		/	/	/
20		/	/	/
25		/	/	/
30		/	/	/
35		/	/	/
40		/	/	/
45		/	/	/
50		/	/	/
55		/	/	/
60		/	/	/
Average Meter Temperature, °F	**(Tm)**	-- / --	-- / --	-- / --
Average Meter Temperature, °R	**(Tm)**	-- / --	-- / --	-- / --
Barometeric Pressure, in. Hg	**(Pb)**	--	--	--
Meter Orifice Pressure , in. WC	**(ΔH)**			
Meter Pressure, in. Hg	**(Pm)**	--	--	--
Standard Meter Volume, ft^3	**(Vmstd)**	--	--	--
Analysis Type		Volumetric	Volumetric	Volumetric
Impinger 1, Pre/Post Test, mL		/	/	/
Impinger 2, Pre/Post Test, mL		/	/	/
Impinger 3, Pre/Post Test, mL		/	/	/
Impinger 4, Pre/Post Test, g		/	/	/
Volume Water Collected, mL	**(Vlc)**	--	--	--
Standard Water Volume, ft^3	**(Vwstd)**	--	--	--
Moisture Fraction Measured	**(BWSmsd)**	--	--	--
Moisture Fraction @ Saturation	**(BWSsat)**	--	--	--
Moisture Fraction, unitless	**(BWS)**	--	--	--
DGM Calibration Check Value	**(Yqa)**	--	--	--

Visible Emissions Evaluations

Project No.		
Facility Name		
Facility Location		
Date		
Observation No.		
Source of Emissions		
Stack Height	ft	
Distance from Source	ft	
Direction from Source		
	Start	*End*
Time		
Wind Direction (From)		
Wind Speed	mph	mph
Ambient Temperature	°F	°F
Sky Conditions		
Color of Background		
Plume Color		
Steam Plume? (y/n)		
Attached to Stack? (y/n)		

Draw the symbols in the diagram below.



The highest six (6) minute rolling average was **0.0**

Rolling Average > 20% **0**

Rolling Average > 40% **0**

Additional Comments

Observations

min	0	15	30	45	min.	0	15	30	45
0					30				
1					31				
2					32				
3					33				
4					34				
5					35				
6					36				
7					37				
8					38				
9					39				
10					40				
11					41				
12					42				
13					43				
14					44				
15					45				
16					46				
17					47				
18					48				
19					49				
20					50				
21					51				
22					52				
23					53				
24					54				
25					55				
26					56				
27					57				
28					58				
29					59				

Observer's Name ____________________

Observer's Signature ____________________

Certification Agency ____________________

Certification Dates __________ *Lecture* __________ *Field*

Appendix E

Martin Willinger

From: alex.scherer@state.co.us on behalf of APCD Compliance Testing - CDPHE, CDPHE <cdphe_apcd_compliancetesting@state.co.us>
Sent: Monday, May 20, 2019 4:08 PM
To: Martin Willinger
Cc: North, Alexis; rgoetz@outriggerenergy.com; Chris DiMarco
Subject: Re: 19-0812D - Makena Gas Plant 3 Engines NOx CO VOC HCHO - 1 Heater NOx CO SSTP

Mr. Willinger,

In order for the Division to approve the provided protocol please provide answers to the following questions:

1. According to the APENs submitted for AIRS Points 007, 008 and 010 the RICE should have emission factors of .4 g/hp-hr of NOx and .7 g/hp-hr of CO. It is stated in the protocol that Outrigger and Alliance will be testing against the emission factors of 1 g/hp-hr of NOx and 2 g/hp-hr of CO. Please explain why the company is testing against those emission factors and not the ones established in the submitted APENs.

2. Please confirm that you will conduct 3 one hour high load tests for each engine and that the spot check proposal is only to avoid conducting three low load tests for each engine.

3. For the amine reboiler, the Division will expect that fuel consumption, amine unit throughput, and amine circulation rate will be recorded during the test and provided with the test results. Pleas let us know if you are unable to record these parameters.

Please provide answers to the above questions in order to have your protocol approved. If you have any questions please let me know. Thank you.

Alexander Scherer
Environmental Protection Specialist
Oil & Gas Team

P (303) 692-3111 | F (303) 782-0278
4300 Cherry Creek Drive South, Denver, CO 80246-1530
alex.scherer@state.co.us | www.colorado.gov/cdphe/apcd

"Are you curious about ground-level ozone in Colorado? Visit our ozone webpage to learn more."

On Mon, May 13, 2019 at 2:05 PM Martin Willinger <martin.willinger@stacktest.onmicrosoft.com> wrote:

May 13, 2019

USEPA Region 8

1595 Wynkoop Street

NC-8ENF-AT

Denver, Colorado 80202

Office of Enforcement, Compliance & Environmental Justice

Alexis North,

303-312-7005

CDPHE, APCD-SS-B1

4300 Cherry Creek Drive South

Denver, Colorado 80246

RE: Makena Gas Plant – Reboiler & Engines (x3) Performance Test

AST Project No. 2019-0812D

Alliance Source Testing, LLC (AST) is pleased to submit the attached source test plan on behalf of Outrigger DJ Operating LLC for compliance testing at the Makena Gas Plant located in Weld County, Colorado. Testing is proposed for June 12-14, 2019.

Testing will include determining the emission rates of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC) and formaldehyde (HCHO) from three (3) Waukesha L-7044GSI natural gas fired compressor engines (AIRS 007, 008 & 010) and NOx and CO from one (1) natural gas fired amine reboiler (AIRS 004).

The performance test on the three (3) Waukesha L-7044GSI engines (AIRS 007, 008 & 010) will be used to demonstrate initial compliance with 40 CFR Part 60, Subpart JJJJ and Colorado Department of Public Health and Environment (CDPHE) General Construction Permit No. GP02 and the performance test on the amine reboiler (AIRS 004) will be used to demonstrate compliance with CDPHE Air Quality Construction Permit 18WE0503, Issuance 1 and 40 CFR Part 60, Subpart DDDDD.

Feel free to call or email with any comments or questions regarding this test plan.

CCed - Rich Goetz (Outrigger DJ Operating LLC), Chris DiMarco (LT Environmental, Inc.)

Thanks,

Alliance SOURCE TESTING

Marty Willinger

Direct: 720-457-9521 // Mobile: 502-609-7607

5530 Marshall Street // Arvada, Colorado 80002

Last Page of Report